



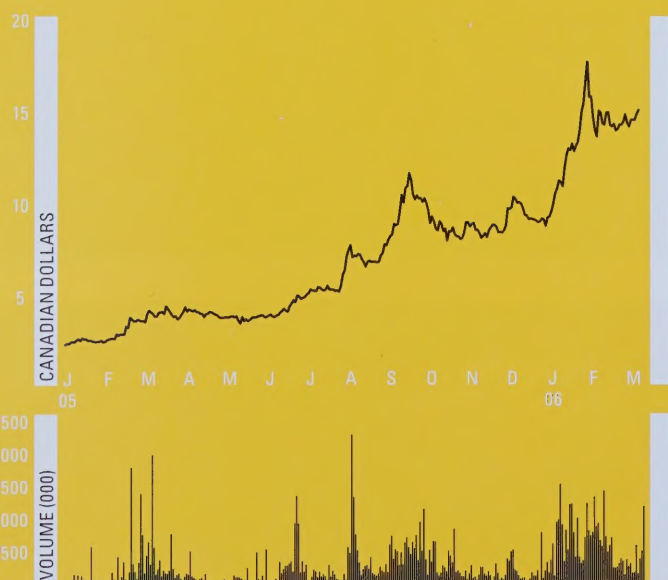
STRENGTH

PETROBANK ENERGY AND RESOURCES LTD. is a Calgary-based oil and natural gas exploration and production company with operations in western Canada and Colombia. The Company operates high-impact projects through three business units. The Canadian Business Unit combines conventional oil and gas operations with two higher potential coal bed methane opportunities. The Latin American Business Unit produces oil through two Incremental Production Contracts in Colombia and has an exploration land base covering a total of 2.5 million acres in the Llanos and Putumayo Basins. The Heavy Oil Business Unit owns 38,400 acres of oil sands leases and is constructing the WHITESANDS pilot project to field-demonstrate Petrobank's patented THAI™ heavy oil recovery process. THAI™ is an evolutionary in-situ combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI™ integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally

ANNUAL GENERAL MEETING The Annual General Meeting of shareholders will be held on Tuesday, May 2, 2006 at 3:00 pm in the Devonian Room of the Calgary Petroleum Club. All shareholders are cordially invited and encouraged to attend.

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Petrobank has world-class projects in each of our three business units. As a whole, they add up to unparalleled **STRENGTH** for a young and dynamic company.



SHARE TRADING (TSX:PB6)

STRENGTH.in our business

CANADA



LATIN AMERICA



HEAVY OIL



units

Petrobank's Canadian Business Unit, operating in the hydrocarbon-rich Western Canadian Sedimentary Basin, is expanding rapidly through successful exploration and development. Conventional oil and gas operations are combined with two significant coal bed methane (CBM) opportunities at Jumpbush, Alberta and Princeton, British Columbia with the potential for substantial incremental reserve additions. The business unit replaced more than 400% of production and increased proved plus probable reserves to 11.6 million boe. Leveraging our extensive undeveloped land base and regional expertise, our technical team is building a significant inventory of drilling locations in existing and evolving new core areas.

Our Latin American Business Unit, operating as Petrominerales Colombia Ltd., is headquartered in Bogotá, Colombia. Petrominerales has Incremental Production Contracts at Orito in southern Colombia's Putumayo Basin and at Neiva in the Upper Magdalena Valley that together produced an average of 1,031 bopd in 2005. Proved plus probable reserves from these two blocks increased 70% to 16.1 million barrels. Leveraging off this solid base of production and reserves, the business unit has successfully negotiated agreements on 2.5 million acres of exploration land in two of Colombia's most prospective basins under Colombia's attractive new fiscal regime.

Our unique Heavy Oil Business Unit continues to develop what may be the most exciting opportunity in the oil industry today. We are conducting the first field demonstration of our patented THAI™ technology at the WHITESANDS site in Alberta's oil sands. The business unit recently increased its oil sands acreage by 33% to a total of 60 sections and commenced initial start-up at the pilot site. This revolutionary process for the in-situ production of bitumen and heavy oil could significantly change heavy oil production worldwide.

STRENGTH in our achievements

2005 PERFORMANCE HIGHLIGHTS

CANADA

- Development program increased production in each successive quarter from 1,927 boepd in Q1 to 3,127 boepd in Q4, exiting the year at 4,000 boepd
- Proved plus probable reserves grew 27% over 2004 to 11.6 mmboe
- Proved plus probable reserve additions replaced 422% of 2005 production
- Drilled 83 wells (57.6 net) with a 96% success rate
- Netbacks doubled to \$33.35 per boe
- Expanded existing core areas

LATIN AMERICA

- Drilled three wells in the southwest area of the Orito field confirming a significant extension to the pool
- Proved plus probable reserves grew 70% over 2004 to 16.1 mmboe
- Netbacks improved 23% to \$39.84 per boe
- Production increased to 1,400 bopd in early 2006
- Negotiated new exploration contracts covering 2.5 million acres of land in two of Colombia's most prospective basins

HEAVY OIL

- Completed an equity financing to fund a large portion of the initial WHITESANDS construction costs, retaining an 84% interest in the project and 100% of all international THAI™ development opportunities
- Obtained non-dilutionary \$9 million financing from Technology Partnerships Canada
- Construction at pilot site nearly completed
- Submitted worldwide patent for THAI™ process enhancement
- Technology-sharing agreements signed with various state oil companies – Petrobras (Brazil), Ecopetrol (Colombia), PetroEcuador and Petro China
- By early 2006, acquired an additional 15 sections of oil sands leases bringing the total to 60 sections – expected to add significantly to 1.3 billion barrel oil sands resource base

2006 – OUR PLANS

- Plan to drill approximately 120 wells (90 net)
- Continue development drilling pace
- Execute focused exploration program
- Leveraging extensive 313,000 acre undeveloped land base
- Acquire additional land and seismic in key areas



- Drill first exploration well in the Llanos Basin
- Complete Petrominerales initial public offering
- Drill up to six development wells at Orito
- Evaluate Las Aguilas prospect
- Drill up to 10 development wells at Neiva
- Complete phase one commitments on new exploration blocks – identify drillable prospects for winter (dry-season) 2005/2006



- Initial start-up of the WHITESANDS project occurred in February 2006 on the first pair of wells
- All three well-pairs to be on combustion by year end
- Internationally, continue to make inroads with our THAI™ process through current technology agreements and new initiatives
- Commence CAPRI™ test
- Additional seismic and stratigraphic drilling
- Evaluate conventional heavy oil reservoir
- Advance research and development



STRENGTH in our performance

HIGHLIGHTS

Financial ⁽¹⁾

(\$000s, except where noted)	2005	2004	% change
Oil and natural gas revenue	65,081	73,377	(11)
Cash flow from operations ⁽²⁾	29,152	23,397	25
Per share – basic (\$)	0.50	0.43	16
Per share – diluted (\$)	0.49	0.43	14
Net income	12,808	833	1,438
Per share – basic (\$)	0.22	0.02	1,000
Per share – diluted (\$)	0.21	0.02	950
Capital expenditures	118,152	47,901	147
Property dispositions	-	143,027	(100)
Net debt ^{(3) (4)}	60,808	35,183	73
Common shares outstanding, end of year (000s)			
Basic ⁽⁴⁾	63,220	54,956	15
Diluted	68,451	59,758	15

Operations ⁽⁵⁾

Canadian operating netback (\$/boe except where noted)			
Oil and NGL revenue (\$/bbl) ⁽⁶⁾	60.96	25.42	140
Natural gas revenue (\$/mcf) ⁽⁶⁾	8.09	5.99	35
Oil and natural gas revenue ⁽⁶⁾	50.84	31.84	60
Royalties	10.46	7.17	46
Production expenses	6.05	7.07	(14)
Transportation expenses	0.98	0.94	4
Operating netback	33.35	16.66	100
Colombian operating netback (\$/bbl)			
Oil revenue	53.62	43.70	23
Royalties	4.29	3.51	22
Production expenses	9.49	7.67	24
Operating netback	39.84	32.52	23
Average daily production			
Canada – oil and NGL (bbls)	452	1,732	(74)
Canada – natural gas (mcf)	11,810	16,196	(27)
Total Canada (boe)	2,420	4,431	(45)
Colombia – oil (bbls)	1,031	1,359	(24)
Total Company (boe)	3,451	5,790	(40)
Proved plus probable reserves ⁽⁷⁾			
Canada – oil and NGL (mmbbls)	1,048	415	153
Canada – natural gas (bcf)	63.5	52.4	21
Colombia – oil (mmbbls)	16,085	9,465	70
Total Company (mboe)	27,720	18,616	49
NPV 10% before tax (\$ millions)	520.3	226.1	130

(1) The financial information for 2004 has been restated for a change in accounting policy.

(2) Calculated based on cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled.

(3) Includes working capital (deficiency) and subordinated notes.

(4) On February 7, 2006, the Company issued an additional 2,597,403 common shares bringing the total number outstanding to 65,817,124, for gross proceeds of \$33.4 million in connection with a public offering and secondary listing on the Oslo stock exchange.

(5) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent ("boe").

(6) Canadian sales prices are shown after hedging costs.

(7) Company working interest reserves excluding royalty interest reserves and before deduction of royalties payable. No reserves have been recorded on the Company's exploration blocks in Colombia or on the Company's oil sands leases.



nice

LETTER FROM THE PRESIDENT

Petrobank has three strong business units – the Canadian Business Unit, Heavy Oil Business Unit and Latin America Business Unit. Each is independently managed and responsible for developing its own opportunity portfolio and maximizing inherent values. They all have strength in their assets and people. Each of these business units has world-class projects that create the potential to evolve into separate corporate entities with the resources to stand alone in the global energy business.

In 2000, with a view to creating greater value for shareholders, we embarked on a new business direction. Since then, we have transformed that vision to value, notably through the realignment of our asset base and strengthening of the balance sheet. A buoyant industry environment, strong commodity prices and improving fiscal terms in Colombia have all provided a backdrop for our efforts. Yet the strength of our asset portfolio allows us to weather the many challenges in our industry – rising costs of equipment and services, geopolitics and the vagaries of world oil prices. At times we can look beyond those challenges and assess what we have created as a Company, and what potential value we have yet to create. Some of last year's key accomplishments include:

- The Canadian Business Unit doubled production through 2005 ending the year at 4,000 boepd, all added through the drill bit.
- Canadian proved plus probable reserves increased 27 percent after production, and proved reserves were up 49 percent year over year.
- Our Colombian proved plus probable reserves increased 70 percent. We have negotiated contracts covering 2.5 million acres of exploration lands in two highly prospective regions, the Llanos and Putumayo Basins.
- Our Heavy Oil Business Unit has converted a concept to reality, taking the WHITESANDS project off the drawing board and into the field, constructing the first field application of the THAI™ process.
- We increased our Canadian oil sands land holdings by 33 percent to a total of 38,400 acres.
- Corporately, we obtained nearly \$100 million of new funding and repurchased \$50 million of our outstanding subordinated notes during 2005.
- In early 2006, Petrobank listed on Norway's Oslo stock exchange raising an additional \$33 million. This transaction has set the stage for the IPO of our Colombian subsidiary, Petrominerales Colombia Ltd. (Petrominerales).
- All three of our business units maintained a solid record of meeting or exceeding all relevant standards for health, safety and environmental protection. We also continue to proactively maintain positive community relations in all of our operating areas.

Each of our business units has world-class projects that create the potential to evolve into separate corporate entities with the resources to stand alone in the global energy business.



John D. Wright
President, Chief Executive
Officer and Director

We entered 2006 with a deep inventory of development drilling locations and exploration prospects which will carry us through the year and well beyond.



We are now poised for major production increases to complement the significant growth in proved, probable and possible reserves in 2005.

Year in Review Canada

The Canadian Business Unit has always filled the role of generating cash flow as a growth platform for the rest of the Company. The Unit has pursued a very opportunistic business model based on acquiring under-developed properties and enhancing their value through capital investment. The result has been highly marketable mature producing properties. While we have regularly sold fully developed assets with little further upside potential, we have constantly strived to increase our undeveloped land base and future growth opportunities, creating a robust platform for sustainable growth and meaningful value creation.

In 2005, the Canadian Business Unit had an excellent year, making a smooth transition from 2004 when we were primarily focused on developing and disposing of fully matured properties in our portfolio. In 2005, we concentrated on organic growth on our existing under-developed properties, primarily at Jumpbush and Red Willow. The result was a doubling of production.

We entered 2006 with a deep inventory of development drilling locations and exploration prospects which will carry us through the year and well beyond. We have also amassed a large and diverse undeveloped land base of some 313,000 acres, with about 50 percent being fee-title lands where we own the mineral rights in perpetuity. This resource base is a firm foundation for our future growth plans. When combined with our drilling success, our development drilling opportunities and our exploration prospects, we believe we have an excellent platform for future profitable growth in the Western Canadian Sedimentary Basin.

Year in Review Latin America

In our Latin American Business Unit, we are now well on our way to transforming our subsidiary, Petrominerales, into a fully independent exploration and development Company. With our solid asset base in Colombia we are beginning to look farther afield to other prospective parts of Latin America.

2006 marks the 10th operating year for Petrominerales and its predecessors in Colombia. Throughout that time, we have worked hard to build a platform of development opportunities and to add focused exploration upside. Compared to 2003, when we held a suite of contractual commitments and no production or reserves, we are now poised for major production increases to complement the significant growth in proved, probable and possible reserves in 2005.

This transition was not without its challenges, as we have faced various technical and operational difficulties over the past three years. As our understanding of our reservoirs has evolved, we have become more confident in the potential of our current producing fields. Our confidence has been bolstered further by an independent reserve assessment that has confirmed the upside inherent in our development program.

To complement this development portfolio, Petrominerales commenced an aggressive exploration land acquisition program in late 2004, which has culminated in 10 new exploration contracts covering 2.5 million acres of prospective lands in the Llanos and Putumayo Basins. Petrominerales has accumulated one of the dominant onshore land

bases in the country. As one indication of the strength of our opportunity base, nearly all acreage in the Llanos basin in the vicinity of our blocks has been contracted by our competitors.

For some time now we have discussed a separate Petrominerales initial public offering (IPO). We now intend to issue a minority interest in Petrominerales through an IPO during the second quarter of this year. Initially, Petrobank will retain a majority interest in Petrominerales, but our longer-term plan is to create a fully independent corporate entity. We are considering the future distribution of our retained interest in Petrominerales pro-rata to all Petrobank shareholders, or to sell our Petrominerales holdings through a secondary offering to the general market, or some combination of the two. We believe this process will further unlock unrealized value in Petrominerales and allow our existing and new shareholders to participate in a pure Latin American exploration and production company.

Year in Review Heavy Oil

2005 was the year in which the Heavy Oil Business Unit converted a plan to a reality. We successfully financed, then completed the design and engineering, and commenced construction of the WHITESANDS project, which is the first field application of our patented THAI™ technology. We also put in place the organization to build and operate the project and evaluate the results.

This business unit was created in 2002 when we paired our existing oil sands leases with a THAI™ and CAPRI™ technology use agreement, and began the process of engineering design and regulatory approval for this pioneering concept. We spent considerable resources on validating and advancing concepts around the application of the technologies, which we then ultimately acquired in 2003. Since that time we have filed two new global patents for innovations to our THAI™ patent. All of this intellectual property resides in Archon Technologies Ltd., a company owned by Petrobank and formed specifically to manage and commercialize our proprietary technologies.

Our Heavy Oil Business Unit has considerable strengths. Our extensive oil sands land holdings contain at least 1.3 billion barrels of bitumen in place. Petrobank holds worldwide patents on technologies which could create a step change in the production of Canada's oil sands, and heavy oil production globally. We have signed technology sharing agreements with various state and international oil companies, and we will work to continue to partner with organizations to continue to bring our technologies into the international arena.

HIDDEN STRENGTHS

When we talk about the strengths and resources that Petrobank has developed in each of our business units, we talk about tangible assets that we will ultimately be able to develop and measure their full value. However, there are also hidden strengths within the Company, which permeate each business unit and every level of contribution.

The first of these hidden strengths is the community relations focus that all of us at Petrobank consider our way of doing business. In this sense, I am not talking about superficial commitments to vague concepts of, "Corporate Social Responsibility", or



Petrobank holds worldwide patents in technologies which could create a step change in the production of Canada's oil sands, and heavy oil production globally.



There are some things
at Petrobank that drive
the innovation
- intelligent risk taking
you are not afraid to
step outside of the
conventional thinking
that permeates our
industry today



charitable donations to endear us to particular communities. On the contrary, I am talking about a fundamental perspective about how we do business in a different, and potentially better way. We integrate our corporate goals to deliver value to our shareholders with respect for local communities and the environment.

Petrobank's team represents a broad spectrum of cultures, nationalities and languages. Among our 105 employees we have citizens of 11 different countries able to converse in 18 different languages. This is a key hidden strength as we are able to incorporate a wide variety of experience and diverse points of view that can consistently add value. It also creates the capability to work with ease in different environments. This is especially true in Latin America as the majority of our employees in Calgary and Bogotá are either bilingual or highly proficient in Spanish.

In our Canadian Business Unit, our community-based approach can be seen through our interactions with our First Nation partner at Jumpbush and the greater community in the Princeton area. We see this in our Latin American Business Unit in an approach that integrates local communities into all aspects of our operations, setting a new industry standard in Colombia. We see it in our Heavy Oil Business Unit, not just in our community consultation process, but also in planning for the commercial development of THAI™. Our process could create a source of agricultural or potable water, and a low cost electricity source as spin off benefits to development of heavy oil fields around the world. While our community-based approach can sometimes be more people and time intensive, we firmly believe the result will be superior long-term returns to all stakeholders.

The most important strength at Petrobank continues to be the people who make up this Company. As we've grown and developed, we have continuously added new employees with new ideas and fresh approaches to old issues. As we have developed our portfolio of opportunities, we have been able to attract and expand our depth of specific expertise and innovative talent. Those who have thrived at Petrobank have been the innovators – intelligent risk takers who are not afraid to step outside of the conventional thinking that permeates our industry today. Our recent experience has taught us that innovation leads to further advances and attracts talented individuals who want to share in the growth potential of Petrobank.

FUTURE POTENTIAL

Each of our business units has a roadmap for value creation in 2006 and the years beyond. From a corporate perspective we will continue to focus our efforts on maintaining a solid balance sheet, funding the best concepts and opportunities, and striving to attract and nurture the best team of technical professionals and innovators that our industry has to offer. We are all shareholders and we have always tried and will continue to act in the very best interests of our shareholders. We will also continue to promote strong relationships in all the communities where we do business as we look for new approaches and value-adding initiatives.

With the creation of an independent Petrominerales, we intend to develop an arms-length relationship with Petrobank, facilitating joint ventures on certain projects where all shareholders can benefit, particularly in the extensive heavy oil industry centered in Latin America.

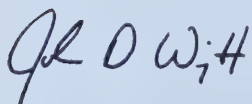
While the implementation of the WHITESANDS project will be a huge milestone for us, we will also strive to apply the THAI™ and CAPRI™ technologies in other reservoirs and in other countries. Our next application will likely focus on a conventional heavy oil pool, which may present a shorter development curve and an immediate commercialization opportunity for the Company.

While we will continue to drill up our broad inventory of development locations in our conventional Canadian operations, we will also dedicate capital and intellectual sweat equity to unlocking further potential upside in our extensive conventional exploration land base, and our unconventional resource opportunity at Princeton.

In many ways our Board of Directors took a big chance in March 2000, permitting the current management team to step in and take the Company in a direction that was outside the boundaries of most conventional oil companies. We are well along a rarely traveled road, with many milestones of successes and failures as learning opportunities. Not all of our plans to-date have worked, and not everything we have in our portfolio today will ultimately bear fruit. But I am confident that the blend of our strengths – resources, people and ideas – will continue to generate growth for the Company and add value for all stakeholders.

With a highly skilled and energetic team of employees, a wise and supportive Board of Directors and a loyal and patient core of shareholders, we have a lot to be grateful for, and I would personally wish to thank everyone who has contributed to our success and who continue to strive for success in the future. As always, this year will bring many changes and challenges and we look forward to enhancing our existing opportunities and creating new ones.

Respectively submitted on behalf of the Board,



John D. Wright

President, Chief Executive Officer and Director

March 15, 2006

STRENGTH. Canada

CANADA

Accomplishments

- Increased production from 1,927 boepd in the first quarter to 4,000 boepd by year end
- Proved plus probable reserves increased 27% replacing 422% of 2005 production

Strategies

- Operate with high working interests
- Exploit and expand existing core areas
- Leverage large undeveloped land base and internal technical expertise into new core areas
- Maintain extensive inventory of drilling locations
- Add value through the drill bit



R. Gregg Smith
Vice President Canada

CANADIAN BUSINESS UNIT

The Canadian Business Unit has been built through the acquisition of under-developed oil and gas properties and exploiting those assets to increase value. After selling a majority of our mature producing assets in 2004, we were able to re-grow our production base, effectively doubling it through 2005. To continue momentum in our drilling programs, we leveraged our significant undeveloped land base, currently 313,000 net acres, into new opportunities.

In 2005, the majority of production growth came from the Petrobank-operated Jumpbush property. We began to expand our Jumpbush position dramatically in 2003 through a series of acquisitions of undeveloped land. The value of the property increased dramatically through active drilling programs in 2004 and 2005, and also with the recent further expansion of our land base in the area. We will continue to add value to this asset with aggressive drilling programs in 2006 and beyond, along with the ongoing expansion of our land position.

The Canadian Business Unit's 2006 plan is focused on growth through the drill bit complemented by strategic exploration into new areas. Through 2006, we plan to drill in excess of 120 wells. This year, fewer expenditures will be dedicated to infrastructure following the completion in 2005 of our large facilities expansion at Jumpbush. The 2006 plan will maintain our development programs at Jumpbush and Red Willow, while we build on our current land positions and success to expand these core areas. Our increased emphasis on exploration activities in 2006 will result in more expenditures on land acquisitions, seismic and exploration drilling.

Our Resources

Petrobank has significantly grown its production base through internally generated exploration and development. We are now positioned for continued growth in our existing core areas, considerable upside through exploration, and the longer-term potential in two significant coal bed methane (CBM) projects.

Producing Properties

Petrobank currently has two main producing areas, Jumpbush and Red Willow. Production from the Canadian Business Unit doubled through 2005 and these properties continue to provide upside through low risk development opportunities.

Undeveloped Land Base

Petrobank has actively accumulated an extensive 313,000 acre undeveloped land base, much of which is non-expiring where we also uniquely own the underlying mineral rights. This asset is unparalleled for most companies our size, providing a strategic advantage in pursuing new opportunities.

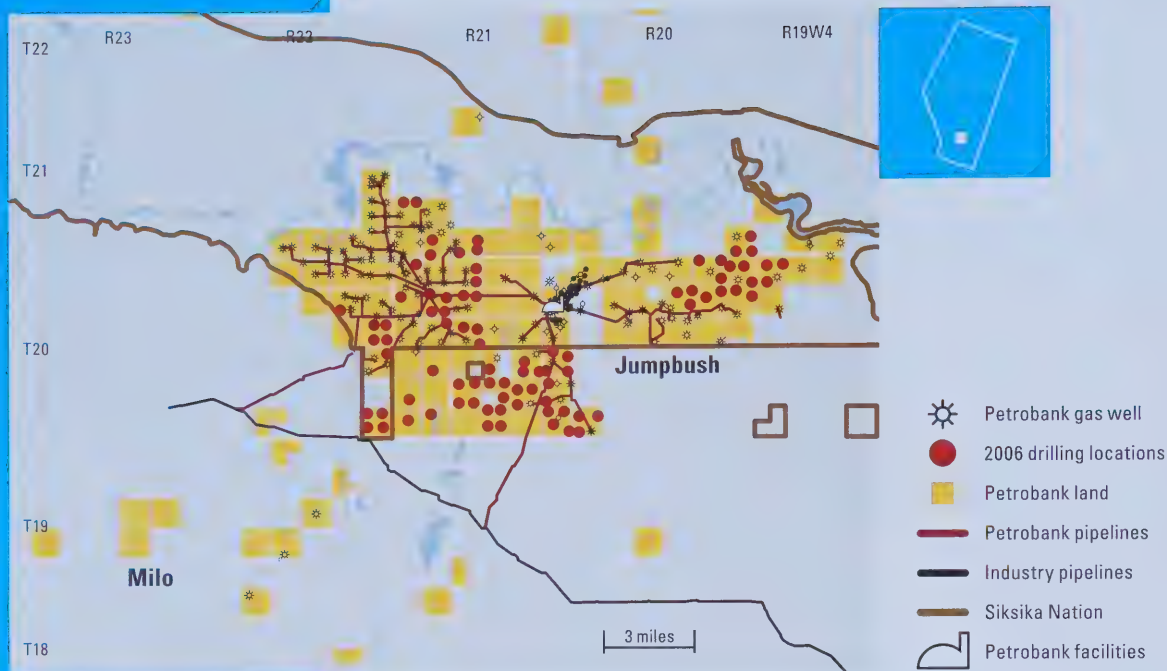
Exploration

Petrobank is continuing to expand its exploration program by building a prospect inventory in areas where we have a strong existing land position and where our technical teams have demonstrated regional success. About one-quarter of our 2006 capital plan is dedicated to exploration.

STRENGTH IN OUR CANADIAN LAND BASE



Jumpbush gas plant expansion from 12 mmcf/d to 25 mmcf/d

**LAND BASE**

65,961 acres
(42,292 net acres)

WORKING INTEREST

70%-100%, operated

PRODUCING WELLS

105 gas wells (71 net),
14 oil wells (10 net)

PRODUCTION PERCENTAGE

62% of 2005 Canadian
production

- 100% drilling success on 79 wells since 2003
- 2005 production increased 179% over 2004 to average 1,505 boepd, 98% natural gas
- December 2005 production averaged 2,143 boepd
- 2005 drilling: 57 wells (40.2 net)
- Expanded gas plant to 25 mmcf/d capacity (17.5 mmcf/d net)
- 4,320 acres acquired (100% working interest)
- 36 square kilometres of seismic acquired
- 2006 plan: drill 80+ wells

JUMPBUSH, ALBERTA

Petrobank's Jumpbush property is predominantly located on the Siksika Nation, approximately 100 kilometres east of Calgary, where we are operator and 70 percent working-interest partner with Siksika Energy Resources Corporation (SERC). Jumpbush is a unique opportunity as it represents a large island of under-developed acreage, surrounded by lands that have been intensely developed in recent years.

Jumpbush is Petrobank's main focus area and generated most of our growth in 2005. The economics at Jumpbush are favourable with low operating costs due to simple processing requirements and an efficient Petrobank-operated facility. The majority of production moves through our centrally-located facilities which have processing capacity of 25 mmcf/d (17.5 mmcf/d net).

The Opportunity

The Jumpbush program is primarily a conventional shallow gas play in the Belly River and Medicine Hat formations. The Belly River formation has several zones capable of natural gas production, with any individual well having a strong likelihood of encountering at least one gas-bearing zone. Petrobank has successfully applied 3-D seismic to identify prolific Belly River gas horizons. By contrast, the deeper Medicine Hat formation and the Milk River formation both contain a single gas-saturated, low permeability sandstone of variable productive capability, which is encountered in almost every well drilled.

We have a total of 221 square kilometres of 3-D seismic covering approximately 70 percent of our land base. Locations are selected according to Belly River mapping, but are drilled to the deeper Medicine Hat formation. Wells are typically drilled to a depth of 830 metres and to date, Petrobank has achieved a 100 percent success rate. The existing capability of wells and infrastructure temporarily restricts production from other shallow gas zones. These zones will contribute incremental gas production over time as field operating pressures decline, resulting in a long reserve life.

In addition, our lands have an extensive coal bed methane (CBM) resource in both the Belly River and Horseshoe Canyon coals, which could further add to the field's reserve life making Jumpbush a legacy asset for Petrobank and the Siksika Nation.

2005 Program

In 2004, Petrobank identified more than 250 drilling locations for shallow gas potential. We drilled 57 (40.2 net) of those wells in 2005, and all were successful gas wells. During the third quarter we completed an expansion of the gas plant capacity to 25 mmcf/d gross (17.5 mmcf/d net) from 12 mmcf/d gross (8.4 mmcf/d net). Pipelines were initially installed for 13 of the new wells (9.1 net) and, during the fourth quarter, we finalized pipeline regulatory approvals and installed an additional 25 kilometres of pipeline to tie-in another 38 wells (26.6 net). Six wells from the 2005 program were drilled for land retention purposes and were not immediately tied-in.

During late 2005 and early 2006 we acquired an additional 6.75 sections (4,320 acres) of freehold lands at 100 percent working interest adjoining our land position. During the fourth quarter a 36-square kilometre 3-D seismic program was acquired in the area offsetting the Siksika Nation on Crown and freehold lands to define additional 2006 drilling locations.

2006 Plan

Expansion of our legacy asset at Jumpbush continues. Along with our significant 2006 drilling program, we plan to acquire additional 3-D seismic and pursue additional land acquisitions through the balance of 2006.

With the newly acquired lands and seismic, we are planning to execute two drilling programs in 2006 totalling approximately 80 wells. The first program of 31 wells is to commence in March and the second program of 50 wells on the Siksika Nation land is expected to commence in August pending regulatory approval. Our 2006 plan also includes up to 20 re-completions, primarily in the Milk River zone and the Belly River coals.

Leveraged Opportunity – Milo

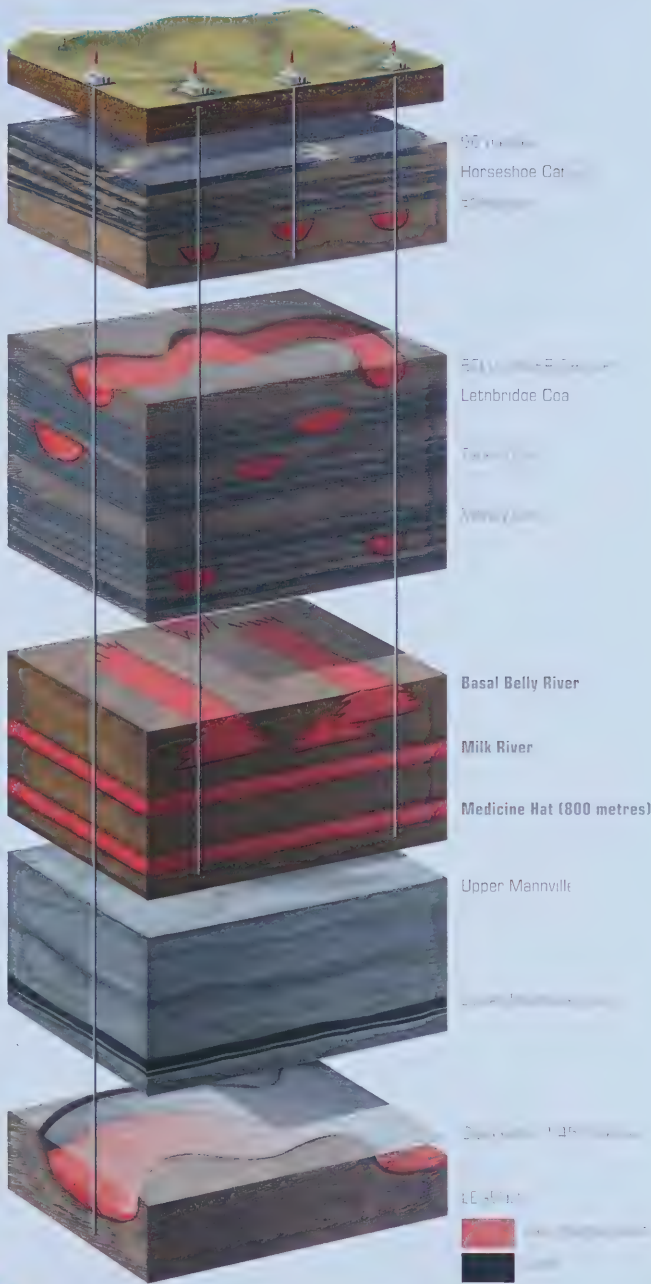
During 2005 and early 2006, Petrobank completed farm-in deals covering eight sections (7.0 net) or 5,120 acres (4,480 net) in the Milo area near our Jumpbush property.

Three exploration wells were drilled in 2005 and cased for shallow gas. We are leveraging our technical ideas and land position at Jumpbush to create a new area for growth. Our 2006 plans include acquiring seismic over the lands and drilling sufficient wells to validate the balance of our land position.

Leveraged Opportunity – Little Bow/Badger

Petrobank is applying our technical expertise gained at Jumpbush to this new evolving area. We increased our land position to 9,440 acres (6,637 net), and we acquired a 24-square kilometre 3-D seismic program in 2005. This has generated an inventory of drilling locations and we plan to drill a minimum of three wells in 2006.

JUMPBUSH CROSS-SECTION



This cross-section illustrates the stacked potential of the Jumpbush area. The extremely shallow section contains the Edmonton zone and the Horseshoe Canyon coals. Most of our wells are drilled to 800 metres for shallow gas potential in the Belly River and Medicine Hat formations. The Belly River zone has several different levels of gas potential throughout this thick formation, including the Lethbridge, Taber and McKay coals, referred to as the Belly River coals. The Medicine Hat and Milk River zones are both regional reservoir intervals that are continuous across our lands, but vary in reservoir quality and ability to deliver gas. Most of our current production comes from the Belly River and Medicine Hat, although increasingly our recompletions in the Horseshoe Canyon coals, Belly River coals and the Milk River are adding to our reserve potential and production. The cross-section also illustrates wells that can be drilled deeper (1,500 metres depth) to the Glauconitic zone. This zone is a channel system with sandstone reservoirs of limited aerial size, but with significant oil or gas reserves depending on thickness. Some wells in 2006 will be drilled to this deeper horizon depending on our 3-D seismic programs.

**LAND BASE**

24,815 acres
(21,954 net acres)

WORKING INTEREST

71-100%

PRODUCING WELLS

15 wells
(14.5 net)

PRODUCTION PERCENTAGE

17% of 2005 Canadian
production

■ 2005 production
averaged 420 boepd

■ December 2005 production
averaged 704 boepd

■ 2005 drilling:
9 wells (9 net)
2 gas wells,
3 oil wells, 4 D&A

■ 2006 plan:
drill up to 15 wells

RED WILLOW, ALBERTA

Located 250 kilometres northeast of Calgary, Red Willow is an attractive property for Petrobank due to the high average working interest, high netbacks, the large number of drilling opportunities and excellent infrastructure. Most wells drilled are 100 percent working interest. Production maintenance is operationally intensive, making it critical to control upstream facilities and maintain high working interests.

Petrobank operates all pipelines, a sour gas plant, satellite compression and two oil batteries. This infrastructure can currently handle all existing production and can be expanded as required.

The Opportunity

The primary drilling targets are the Glauconite and Ellerslie zones within the Mannville Group. Regionally, these sandstone reservoirs are characterized by high-deliverability natural gas and oil. Secondary targets in the area are the Belly River and Viking zones. The Belly River and Viking zones are sandstone reservoirs that tend to have long-term, low-deliverability natural gas. Although typically not Petrobank's specific target, they frequently provide additional up-hole potential while drilling for deeper, more prolific zones.

2005 Program

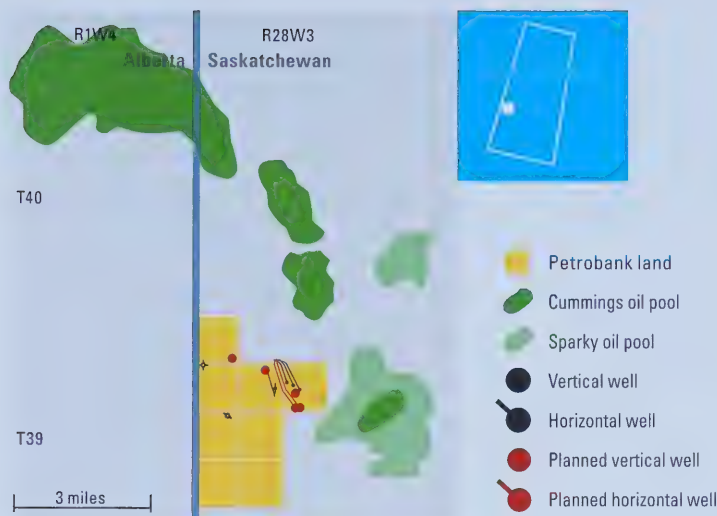
Petrobank drilled nine wells (9.0 net) resulting in two gas wells, three oil wells and four dry and abandoned wells. Activity ramped up during the fourth quarter as the Company drilled two gas wells and one oil well, installed 3.9 kilometres of pipeline to tie-in two wells, and completed a 38-square kilometre 3-D seismic program to identify further 2006 drilling locations.

2006 Plan

The 2006 capital plan anticipates drilling up to 15 wells at Red Willow, as rig availability permits. Additional 3-D seismic is planned for the area to increase our prospect inventory. We recently added 640 acres (640 net) of land and continue to expand our presence in the area.

Leveraged Opportunity – Hackett

Southwest of Red Willow is a new opportunity at Hackett. This area is prospective for many of the same zones as Red Willow along with CBM potential in the Mannville coals. Our land position totals 5.75 sections (3,680 acres – 100 percent working interest). A 3-D seismic program and a first phase of drilling is planned here in 2006.



MACKLIN, SASKATCHEWAN

Macklin is an exploration and development land block along the Saskatchewan-Alberta border with potential for heavy oil in both the Cummings and Sparky formations, as well as gas from other zones. Late in 2004 Petrobank acquired a 3-D seismic program over most of the lands, and identified several exploratory locations to evaluate the Sparky and Cummings zones.

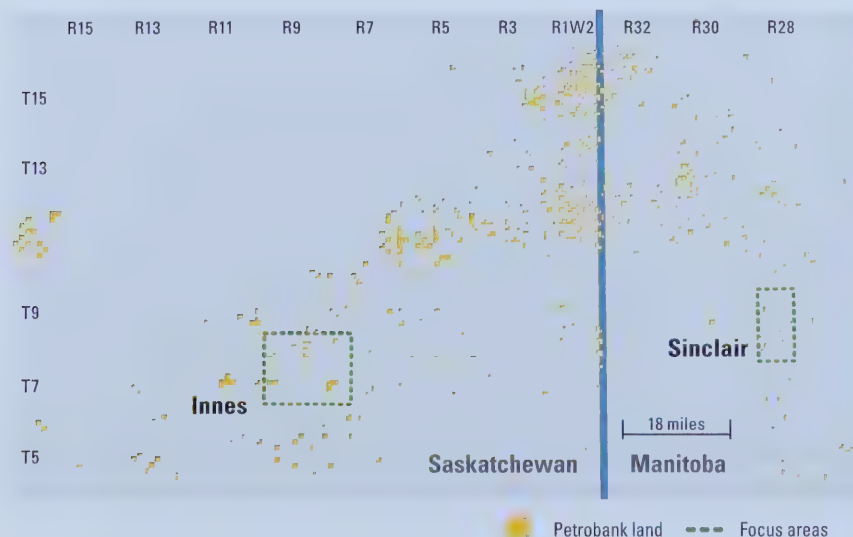
2005 Program & 2006 Plans

Early in 2005 we drilled two exploratory wells. The first was a horizontal well with a vertical pilot hole, which proved up horizontal productive capability from the Cummings as well as potential in the Sparky. The second well was a vertical well, which evaluated the Sparky and the Cummings zones and demonstrated potential in both. Late in the fourth quarter a second horizontal well was drilled and in early 2006 a further two horizontal wells were drilled. Based on preliminary results from these initial wells a development program is planned for 2006 that includes two horizontal wells and three vertical wells, one of which will earn an additional section of land.

EXPLORATION

Beyond our leveraged opportunities at Milo, Little Bow/Badger and Hackett, Petrobank continues to expand our exploration prospect base in areas where we have internal technical strengths and a strong land position. The Company's large undeveloped land position of 313,000 net acres provides a significant platform for future growth.

Petrobank's extensive undeveloped land position also includes non-expiring fee title lands in Alberta, Saskatchewan and Manitoba. These lands have allowed us to monitor industry results and generate a significant amount of royalty income in the Sinclair and Innes areas. This has also allowed us to participate in the evolving Bakken light oil play and we have increased our exposure to this play through recent Crown land sales.



LAND BASE
4,336 acres
WORKING INTEREST
100%
PRODUCING WELLS
4 wells

- December 2005: production 23 bopd, currently 320 bopd
- 2004: shot an 10-square kilometre 3-D seismic program
- 2005 drilling: three oil wells
- 2006 plan: two oil wells drilled, additional locations planned

313,000 acre undeveloped land base, 50% non-expiring fee-title, provides platform for future growth.



Project timeline

2001

Secured coal-mining rights in the Princeton Basin – drilled three mining test wells – confirmed coal resource quality

2002

Acquired petroleum and natural gas rights

2003

Acquired 121-kilometre 2-D seismic program

2004

Drilled first test well – confirmed presence of thick beds with high gas saturations

2005

Completed and fracture stimulated first CBM test well – tested free methane gas and minor amounts of water

Worked on drilling and completion techniques to improve production rates

2006

Assess commerciality by drilling up to four additional wells

PRINCETON, BRITISH COLUMBIA

Petrobank (60 percent working interest) and its partners control the coal and petroleum and natural gas rights over the entire Princeton Basin, an expansive area covering 38,000 acres (22,800 net). The basin contains very thick Tertiary-age, gas-bearing coals. A number of other Tertiary-aged coal-bearing basins are present in southwest British Columbia, the best known being the Hat Creek Basin which contains one of the thickest accumulations in the world at 1,750 feet of coal in a 3,850-foot section.

The Princeton CBM project is attractive due to the large resource potential, and the low cost and ease of tying in production as a pipeline runs through the Princeton property. However, we are taking a measured approach to investing capital. Princeton is a longer-term project as we are continuing to evaluate the coal and production characteristics of the area. The prolonged time frame is also due to the government approval and First Nation and community consultation processes, which are more time-intensive in areas like Princeton as it is relatively new to oil and natural gas activity.

CBM projects normally require a de-watering phase prior to commercial natural gas production. Typical peak production is 50-1,000 mcf/d per successful well. Drilling costs, potential de-watering time and individual well productivity will determine the ultimate commercial viability of this project. This project contains significant long term potential, which could have a dramatic impact on Petrobank's reserve and resource base.

Project Viability

Late in 2004 and into 2005 we drilled and completed our first CBM test well. After fracture treatment, the initial well flowed free methane with only minor amounts of fresh water. This indicates that the coal is fully gas saturated and may not require an extended de-watering period. Although the well did not flow at commercial rates, we are focusing on refining drilling and completion techniques to improve gas production rates in order to move the project closer to commerciality.

The viability of a commercial project will likely require up to four wells in a pilot project that could be drilled in 2006, followed by a 6-12 month production-testing period. Drilling in this area is costly, as equipment needs to be moved from Alberta. A four-well program would cost approximately \$4.0 million (\$2.4 million net). With positive results, plans for developing the resource can be completed and development could commence as early as 2007.

WHAT IS COAL BED METHANE?

Coal bed methane (CBM) accounts for about 10 percent of total gas production in North America but only about one percent of production in Canada with an increasing number of commercial projects being announced

Coal seams naturally emit methane, or natural gas. Drilling for CBM is similar to drilling a typical gas well, and both vertical and horizontal wells can be employed. Production, however, is more complex. Some coal seams have associated water, which must first be produced before the gas will flow. This de-watering phase can take up to several years before peak gas production is reached

Petrobank will meet or exceed strict government guidelines and industry standards for managing any produced water.

CBM is more capital-intensive than a typical conventional natural gas play and the rise in natural gas prices over the past few years has made it more economically viable.

Coal seams tend to hold very large gas resources in place with a long reserve life, but often require more wells than typical conventional gas plays

ENVIRONMENT AND COMMUNITY RELATIONS

Petrobank creates strong relationships in all the communities in which we are active. Specifically, our operations at Jumpbush and at Princeton reflect our commitment to community engagement and dialogue.

At Jumpbush, Petrobank is continuing a constructive relationship with the Siksika Nation, represented by the Siksika Energy and Resource Corporation (SERC) and their resource management agency, Siksika Land Management Service Area (LMSA). Our open and professional relationship with SERC, a 30 percent partner at Jumpbush, is an important factor in our effective and timely development of the Jumpbush field. The Nation's insight continues to ensure our Jumpbush operations are both productive and sensitive to the environmental and cultural realities of the area. Siksika Nation members are employed and trained in various aspects of field operations. Local contractors are regularly hired for their expertise in pipeline work. Moreover, these contractors provide safe, competitive services while generating employment and economic benefits for the community.

Petrobank's relationship with the greater Princeton community has grown considerably since development began on a CBM evaluation well southwest of the Town of Princeton. Since our entry into the community, we have maintained open and frequent dialogue through public presentations, media relations and a series of education-focused newspaper placements.

Community understanding of CBM also relies on an understanding of how government and industry work together to protect community interests, and Petrobank will continue to share information about this important relationship.

Regular availability and communication with the community has been integral to the development of a mutual understanding of the unique economic and environmental issues that are important to area residents.

At Princeton, Petrobank is maintaining its relationship with the Upper Similkameen Indian Band with the intention of developing local employment and business opportunities for the members of the Band and local residents of Princeton.

Petrobank's environmental management approach remains committed to meeting or exceeding government requirements while following industry best practices.



Operations/safety training at Jumpbush

The Siksika Nation's insight continues to ensure our Jumpbush operations are both productive and sensitive to the environmental and cultural realities of the area.



Control wellhead facility at Jumpbush

FUERZA América Latina

LATIN AMERICA

- Proved plus probable reserves increased 70% to 16.3 barrels
- Assembled 2.5 million acre exploration land base in two of Colombia's most prolific basins
- High impact development opportunities
- Petrominerales IPO planned for Q2 2006

COLOMBIAN ASSETS

NAME	APPROX. TYPE	BASIN	ACRES	EXP'DY	INITIAL COMMITMENT	STATUS
Orito	IPC	Putumayo	42,492	06/23	No further commitment /	Producing
Neiva	IPC	Upper Magdalena	2,395	06/23	No further commitment /	Producing
Joropo	Exploration	Llanos	72,257	12/06	Drill one well / Commenced drilling in February 2006	
Corcel	Exploration	Llanos	79,815	09/06	Seismic / 3D in processing	
Casanare Este	Exploration	Llanos	78,814	06/06	Seismic / 3D being interpreted	
Casimena	Exploration	Llanos	107,704	11/06	Seismic / Shooting 150 sq. kilometre Survey	
Las Aguilas	Exploration	Putumayo	33,671	10/06	Seismic / Interpreting 3D survey in conjunction with Orito	
Chicago	TEA/Light Oil	Llanos	433,967	06/06	Reprocess existing data / Will choose exploration block from TEA	
Rio Ariari	TEA/Heavy Oil	Llanos	607,137	08/06	Reprocess existing data, core work / Received data, reprocessing	
Chiguiro	TEA/Heavy Oil	Llanos	539,785	10/06	Reprocess existing data, core work / waiting to sign final agreement	
Guatiquia	TEA/Heavy Oil	Llanos	391,409		Reprocess existing data, core work / waiting to sign final agreement	
Corito	TEA/Light Oil	Llanos	169,642		Reprocess existing data, core work / waiting to sign final agreement	
Total Assets			2,559,088			

LATIN AMERICA BUSINESS UNIT

Petrobank's Latin American Business Unit, Petrominerales Colombia Ltd., headquartered in Bogotá, Colombia, has two incremental production contracts (IPCs) with world class development potential and has secured 2.5 million acres of exploration land under 10 agreements. Three of these areas, totaling 1.5 million acres, are also being evaluated for heavy oil potential and the application of Petrobank's patented THAI™ heavy oil recovery process.

Results from our 2005 activities positioned us to commence aggressive development and exploration programs in 2006. We proved up a significant southwest extension to the Orito field which is expected to lead to at least 10 additional locations in this region that may extend onto our newly acquired Las Aguilas exploration block adjacent to Orito.

The creation of Colombia's new National Hydrocarbon Agency (ANH) in 2004, and the introduction of a new land tenure and fiscal regime have allowed us to assemble a 2.5 million acre exploration land base in two of Colombia's most prolific basins. Our strategy involves applying a Canadian exploration approach to Colombia's vastly under-explored basins.

Our 2006 capital spending plan will focus on the significant potential we have identified on our Orito block, and on refining the potential of our exploration blocks in the Llanos and Putumayo Basins. We will continue to expand our presence in Colombia through the potential acquisition of existing production and additional exploration blocks in selected regions of the country. Suitable acquisitions in other parts of the continent, including Argentina, Ecuador, Peru and Venezuela will continue to be evaluated.



Steven E. Benedetti
Vice President, Latin America



ORITO

The Orito block is located in the Putumayo Basin of southern Colombia, where the Company is partnered with Ecopetrol, the state oil company, in an IPC. During 2005 we completed the first full year of the 19-year complementary phase of the contract where we are responsible for developing the significant reserves that remain in the producing reservoirs of the field. Petrobank initially receives 79 percent of all incremental production in excess of the pre-defined declining baseline production curve.

AVERAGE DAILY ORITO PRODUCTION

	2004	04/2004	CURRENT
Gross field	3,810	3,666	4,137
Baseline	(2,944)	(2,873)	(2,808)
Incremental	866	793	1,329
Petrominerales share before royalty (79%)	685	627	1,050
Royalty (8%)	(55)	(50)	(84)
Petrominerales net of royalty	630	577	966

Geology

The Orito Field, almost 43 square kilometres in area, is the largest field in southern Colombia and is estimated to have originally contained in excess of 1.0 billion barrels of oil in three primary sandstone reservoirs, the Eocene Pepino and the Cretaceous Villeta and Caballos. The most significant is the Cretaceous Caballos formation, which is estimated to have originally contained more than 700 million barrels of oil in place.

The Caballos is a complex series of fluvial/deltaic and marginal marine sands and is the primary producing reservoir in the field. The Caballos zone is interpreted to have a tilted oil/water contact that originally dipped from northeast to southwest at least 280 metres within the field. Crude quality varies from near 30° API in structurally low areas to as high as 43° in the northern, up-dip areas of the field.



Orito Incremental Production Contract

CONTRACT TERM:
09/23

AREA:
43.489 km²

AVERAGE DAILY PRODUCTION:
18,703 bbl/day

PRODUCED TO DATE:
395 bbl

WORKING INTERESTS (PERCENTAGE)

ORITO PRODUCTION:
1.342

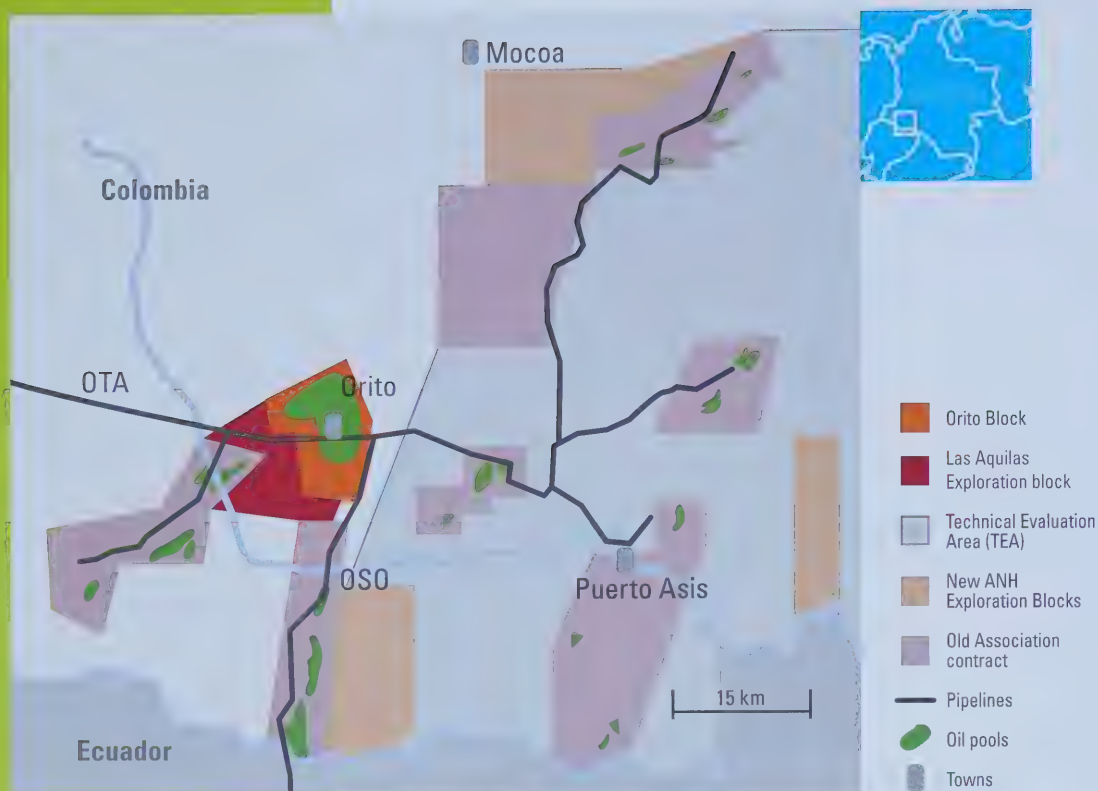
TOTAL SHARE:
3.085

TOTAL PROVED RESERVES:
13,269

TOTAL PROVED PROVED & PROVED:
18,527

PROVED WELL DEPTH:
7,000 m

PROVED WELL DEPTH:
13,860 m



We have identified at least 10 additional Caballos drilling locations in the southwest region of the Orito field and a prospect on our adjacent Las Aguilas exploration block.



The recently updated reserves report of DeGolyer and McNaughton indicates 27 million gross barrels of incremental proved, probable and possible reserves to be developed from the Caballos reservoir. To date, the field's reservoirs have produced 225 million barrels of oil, or approximately 22 percent of the estimated original oil in place. The Caballos zone has produced 186 million barrels since the field was discovered in 1963.

2005 Program

In 2005 we initiated our development plan targeting the southwest extension to the Orito field. Three wells, Orito 116, 117 and 118, were drilled during the year. Drilling went as scheduled for each well, but due to problems encountered during logging and completion operations, expected production from these three wells has been delayed into 2006.

The Orito 116 well tested significant oil from the Cretaceous Caballos 'A3' and 'A4' sands as well as water-free production from the Caballos 'B', 'C' and 'D' sands; however immediately after installing the final electrical submersible pump (ESP) completion assembly, the well experienced a casing collapse. The current plan is to sidetrack this well later in 2006.

The Orito 117 well has produced approximately 150 bopd from the Caballos 'A' sands, but with water cuts as high as 98 percent. We are recompleting the well to shut off the water in the lower 'A' interval, and fracture stimulating the 'B', 'C' and 'D' sands.

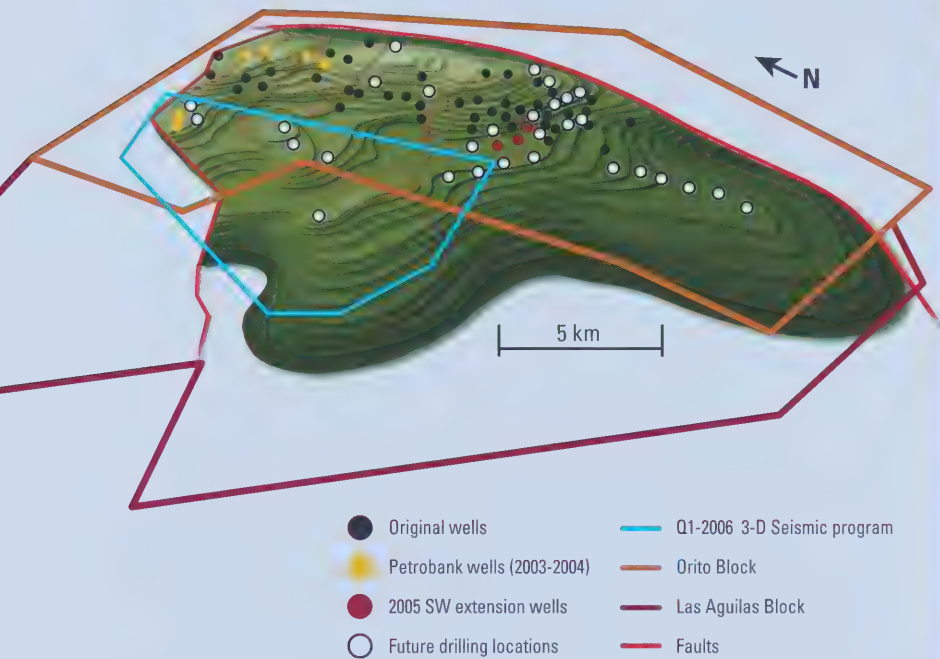
In the Orito 118 well we experienced a collapsed hole which resulted in the well being sidetracked. We perforated and fracture stimulated the Caballos 'B', 'C' and 'D' sands and tested the uppermost Caballos 'A3' and 'A4' sands. With the installation of ESPs we are targeting approximately 500 bopd from each well in the southwest extension. Based on these economic quantities of oil in the southwest extension to the field and newly acquired 3-D seismic, at least 10 additional Caballos locations have been identified in this region of the field, as well as an additional prospect on our adjacent Las Aguilas exploration block.

During the fourth quarter of 2005 we acquired a 40-square kilometre 3-D seismic survey covering the western part of the field and a prospect on our Las Aguilas exploration block. This seismic confirmed the continuation of the southwest extension, and the Las Aguilas prospect. Additional locations are confirmed targeting the area northeast of our Orito 113 well and another west lead, south of our existing Orito 113 well.

2006 Plan

The 2006 Orito plan will focus initially on continuing our successful fracture stimulation program in an additional seven wells. We have secured a drilling rig for an initial 16-24 month contract, which is scheduled to start a continuous drilling program at Orito in mid-2006. This rig is also capable of drilling our deeper prospects in the Llanos Basin.

In the first quarter of 2006, we commenced a program to open the uppermost 'A' sand, the 'A4' interval, in selected wells and fracture stimulated the upper 'B', 'C' and 'D' sands in those same wells and others. We have performed fracture treatments on five wells and opened the upper 'A' sand interval in four of them. All treatments and tests have been successful, resulting in production increases ranging from 50 bopd to 200 bopd per well. Additional production is expected after installation of ESPs in these wells, which commenced in early March 2006.



NEIVA

The Neiva block is located in the Upper Magdalena Valley in central Colombia, where the Company is partnered with Ecopetrol in an IPC. We completed the first full year of the 19-year complementary phase of our Neiva contract during 2005. The Company initially receives 69 percent of all incremental production in excess of the pre-defined declining baseline production.

AVERAGE DAILY NEIVA PRODUCTION

	2005	99 PROD	COMMENT
Gross field	2,993	2,910	2,893
Baseline	(2,492)	(2,435)	(2,386)
Incremental	501	475	507
Petrominerales share before royalty (69%)	346	328	350
Royalty (8%)	(28)	(26)	(28)
Petrominerales net of royalty	318	302	322



The Orito Block is located in the Upper Magdalena Valley in central Colombia, where the Company is partnered with Ecopetrol in an IPC. We completed the first full year of the 19-year complementary phase of our Orito contract during 2005. The Company initially receives 69 percent of all incremental production in excess of the pre-defined declining baseline production.

Orito Incremental Production Contract

CONTRACT TERM
10/05/05

AREA
2,500 acres

APPROXIMATE RESERVE
US 201,770 bbl

PRODUCTION 2005
240 bopd

REVENUE SHARING SUMMARY

PERIOD PRODUCTION
(2005)

TOTAL PRODUCE
1,517

TOTAL BEFORE & MINUS
2,816

TOTAL PRODUCE, PRODUCTION & MINUS
3,736

INVESTMENT COST
2,000 bopd

TYPICAL WELL COST
US \$1.0 million

The combination of fiscal terms and hydrocarbon prospectivity in Colombia are widely considered to be the best in the world.



Wellhead in the Putumayo Basin

2005 Program

Our 2005 activities at Neiva focused on aligning the contractual terms to provide a more economically viable vehicle for all partners, including a proposal to drill a number of infill wells for a higher percentage of the incremental production from those wells. As we were unable to reach an agreement with Ecopetrol, our field activity in 2005 was limited to surface equipment optimization that allowed production to remain relatively flat throughout the year and increase slightly early in 2006.

Neiva Geology

Neiva production is primarily from a series of thick Tertiary sandstones in the Honda formation totaling approximately 800 gross feet of pay at a maximum depth of 3,500 feet. We have also added production from the slightly deeper Doima-Chicoral reservoir, which is a thick conglomerate trapped along the flank of the main Neiva structure as an angular unconformity.

2006 Plan

We plan to drill up to seven Honda infill wells and three Doima-Chicoral development wells in 2006. We are also evaluating a fracture stimulation program of selected wells in the Honda reservoir during the year, along with a pilot waterflood project.

NEW VENTURES

Colombia's New Fiscal Terms

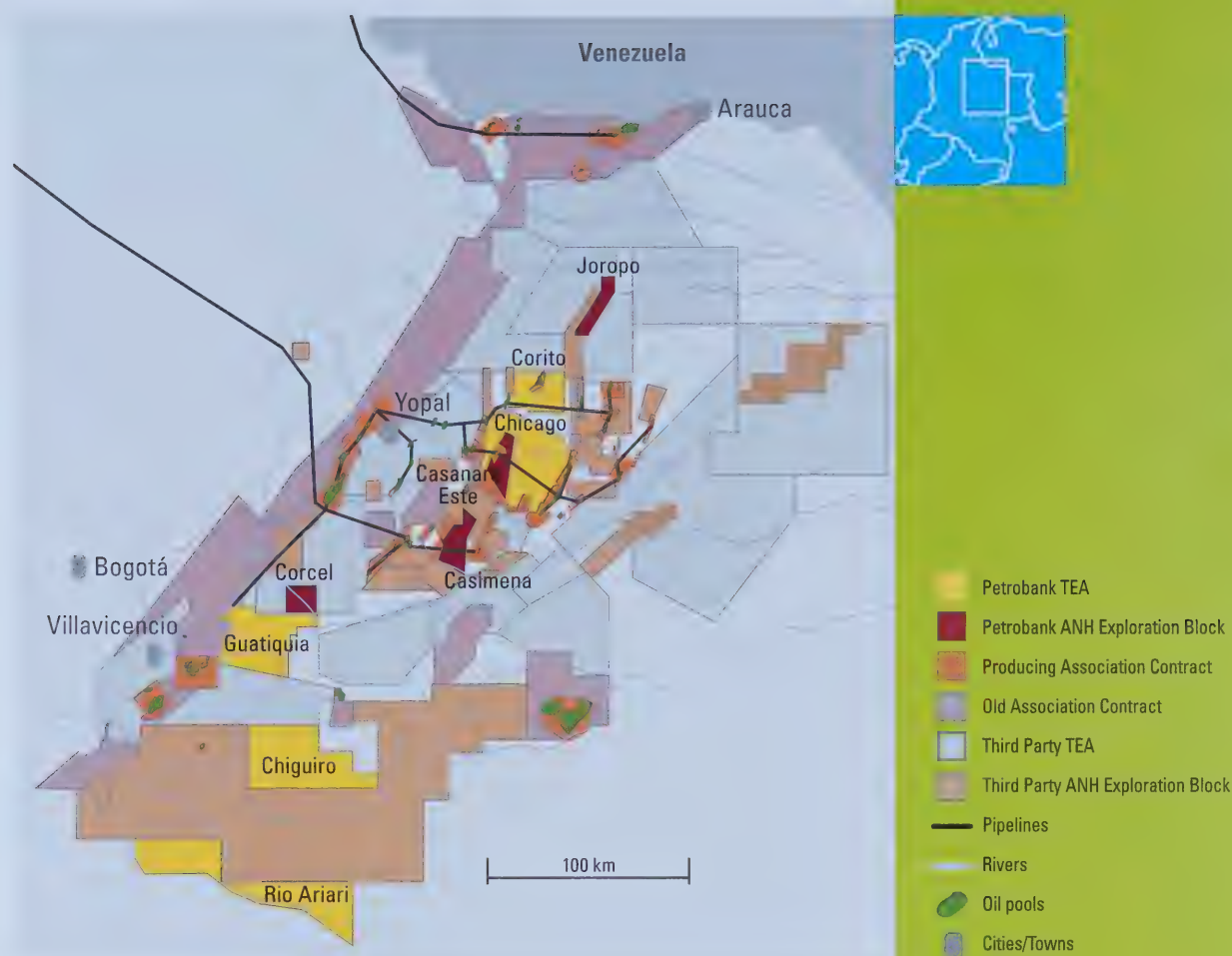
Exploration is playing an increasingly important role in our activities in Colombia. During the course of the year, Petrominerales took advantage of the opportunities provided under the new exploration contracts now being offered by the National Hydrocarbon Agency (ANH). All operators were afforded access to any uncontracted lands by committing to a minimum exploration work plan with no initial land costs. Contractors obtain access to all available geological and geophysical data, and initial work commitments typically involve shooting new seismic within the first year. Companies can then drop the block or extend the contract for an additional year by electing to drill an exploration well. The exploration period can normally be extended for up to six years by drilling additional wells.

Once commerciality of a field is declared, the development phase lasts an additional 24 years, which can be extended in certain circumstances for another 10 years or for the life of the reserves. These new terms provide a successful company the right to all reserves and production from newly discovered fields, subject to normal royalties (initially eight percent) and income taxes (2006 – 38.5 percent, 2007 – 35 percent).

Since the introduction of these new contract terms, 52 exploration blocks and 35 technical evaluation areas (TEA), covering a total of 52 million acres, have been licensed through the end of 2005, with in excess of 20 more pending approval by the ANH technical committee and board. TEAs are typically larger in size and have lower initial commitments, which include reevaluating existing data with a view to defining prospects and ultimately committing to an exploration block. If a third party proposes an exploration block within an existing TEA, the holder has the right to match the proposed work program and retain the block. The combination of fiscal terms and hydrocarbon prospectivity in Colombia are widely considered to be the best in the world.

New Ventures Strategy

Our new ventures strategy is focused on areas where we have technical expertise and an operating advantage, primarily in the Putumayo Basin (Orito), Upper Magdalena Basin (Neiva) and Llanos Basin. Our intention is to focus on the technical strengths we apply in our Canadian Business Unit, centering on 3-D seismic interpretation, data reprocessing and targeting new stratigraphic prospects and conventional structural prospects. We have signed contracts on four highly prospective exploration blocks in the Llanos Basin and one block that is contiguous with our Orito block in the Putumayo Basin. We have also negotiated five TEAs in the Llanos Basin, three of which have heavy oil potential. Our plan for the initial phase on the exploration blocks includes reprocessing existing seismic data and acquisition of 3-D seismic to identify and confirm the most significant prospects on each block.



Llanos Basin Geology – Plains Region

In the Llanos Basin, productive traps are formed by a series of “up to the basin” faults. Tertiary and Cretaceous sandstone reservoirs trap hydrocarbons against these faults. Production, quite often as high as 2,000 bopd per well, may come from up to four or five individual sands. Pools in this region of the Llanos Basin have ranged from three to 45 million barrels. Our first Llanos exploration well drilled on the Joropo Block targeted the main ‘C7’ sand in the Tertiary Carbonera formation and was recently abandoned.

Putumayo Basin – Las Aguilas Exploration Block

In the latter half of 2005 Petrominerales acquired the Las Aguilas Block in the Putumayo Basin, which is contiguous with our Orito Block. A 3-D seismic survey has been finalized allowing us to identify a potentially significant structure to the southwest of the Orito field.

The initial interpretation of the 3-D seismic has confirmed that an earlier exploration well, drilled off 2-D seismic by a competitor, was approximately 350 feet lower than the apex of the target structure. As we would receive 100 percent of all revenue related to any discovery on the block, we are focusing on evaluating this structure and, pending success, would move quickly to complete the development of any new discovery.

THAI™ in Latin America

In parallel with the initiation of our THAI™ pilot project in Alberta, we have begun evaluating the potential of similar projects in Colombia, Brazil and Venezuela. To date we have secured three large TEAs in Colombia’s Llanos Basin, which are prospective for both conventional heavy oil and potentially the application of THAI™. Petrominerales is finalizing a non-exclusive licensing arrangement for the use of the THAI™ technology from Archon Technologies Ltd, a 100 percent-owned subsidiary of Petrobank.

Petrominerales has established a community relations approach that is based on three principles:

- 1 Local employment
- 2 Education and training
- 3 Community engagement

ENVIRONMENT, COMMUNITY RELATIONS AND SECURITY

Environment

The Company continued its third year of operations in Colombia with 100 percent environmental compliance in executing our development programs and without any lost time accidents or environmental incidents. Our social responsibility strategies include environmental compliance and promoting fundamental relationships with local communities and the provincial and national authorities.

The Ministry of Environment in Colombia requires environmental licenses for all new exploration activity in accordance with strict national regulations. Our comprehensive environmental impact assessments and management plans ensured that we obtained the environmental license for our first exploration well in the Joropo Block in the shortest time possible. We also presented and received approval for our environmental management plans covering 3-D seismic projects on the Casanare Este, Corcel and Casimena exploration blocks.

Community Relations

Petrominerales has established a community relations approach that is based on three principles:

- **Local employment** is promoted by identifying, providing and supporting job opportunities within our operating areas. This has been well received by the local communities and contributed to maintaining a positive relationship in and around our operations.
- **Education and training** programs are focused on strengthening the relationships between communities and the local authorities and on helping communities identify new markets for their goods and services to reduce their dependence on the oil business. Our approach also encourages local community engagement in the government development planning process, and reinforces the link between oil revenues and municipal budgets.
- **Community engagement** creates a partnership in the preparation of environmental base line studies for local environmental management, which strengthens our relationship with communities by combining our expertise and environmental approach with local knowledge of the environment and land management. We are continuing to build a relationship of trust by encouraging communities to become involved in all aspects of our environmental management processes.

Our approach has been cited by both the government and the oil industry as the best practice model to follow.

As an example of this approach, we recently conducted a highly successful community consultation process with the traditional Embera people of the La Venada indigenous reservation in connection with our west Orito/Las Aguilas 3-D seismic project. In Colombia during 2005, 99 indigenous consultation processes were undertaken by industry, with only three yielding positive agreements. Our agreement resulted in the participation of indigenous representatives in our environmental impact studies, which covered an important portion of their traditional territory. Our process produced a set of agreements with the people of La Venada that, in the national context, was accomplished in a very short time frame and at a low cost. By the end of 2005, the seismic acquisition was completed with total environmental compliance and no health or safety incidents.

Fundación Vichituni

Petrominerales has created and initially funded Fundación Vichituni to assist in developing and enhancing basic social and environmental values in the regions directly influenced by the Company's operations. Vichituni, from the traditional Embera language, translates as "you are worthy".

Fundación Vichituni's mission is to promote community growth and an enhanced quality of life. This Foundation involves entire communities, governments and third party partners contributing to the creation and completion of educational projects with a focus on developmental issues.

After comprehensive research and a careful strategic planning process, the Foundation has created two main lines of work in which this community development program will be focused:

- Working with authorities and communities in the Land Use Plan of Putumayo, which will strengthen the local government's capacity to plan their development; and
- Increasing the knowledge of the cultural and traditional diversity of the communities in Putumayo, allowing a better use of the land by harmonizing diverse development approaches.

The Foundation is also seeking international funding and partnerships with the goal of self-sustainability within the first two years of its operation.

Security

Although there are certain security risks associated with operating in Colombia, as there are in many places worldwide, we believe these risks can be effectively managed.

Working with local communities promotes an atmosphere of mutual respect, benefit and trust, and thereby decreases the risk of serious security issues. Within Bogotá and in our field operating areas, we maintain contact with appropriate local, regional and national bodies to monitor any local security situations and mitigate risk.

PETROMINERALES IPO

The Petrominerales initial public offering, planned for the second quarter of 2006, will provide the next phase of capital required to fuel growth in Colombia. Initially, Petrobank intends on retaining a majority interest in Petrominerales, which subsequently can be distributed to Petrobank shareholders or sold through a secondary offering generating capital to fund growth prospects in our other business units.

LOOKING AHEAD

Our 2006 plan:

- Drill our first exploration well in the Llanos Basin
- Complete Petrominerales initial public offering
- Drill up to six development wells at Orito
- Evaluate Las Aguilas prospect
- Drill up to 10 development wells at Neiva
- Complete our phase one commitments on our new exploration blocks – identify drillable prospects for winter (dry-season) 2006/2007
- Assess heavy oil potential and THAI™ applicability on significant Llanos Basin acreage

We view the recent fiscal changes in Colombia as very positive for the future of the country and Petrominerales. Colombia is one of the longest-standing democracies in Latin America with the longest unbroken history of foreign direct investment. It is clear from the manner in which international companies are treated that the government continues to be committed to advancing their plan of economic growth.

We have long considered Colombia to be one of the best places to invest in the oil industry, a fact that has just recently become more widely recognized. In no other country could Petrominerales have assembled such a highly prospective 2.5 million acre exploration land position at virtually no initial cost. Our combination of high impact development opportunities with considerable exploration upside is expected to provide the platform for growth both in Colombia and the surrounding basins for many years to come.



Colombia is one of the longest-standing democracies in Latin America with the longest unbroken history of foreign direct investment.

The Petrominerales initial public offering is planned for the second quarter of 2006.

STRENGTH $\equiv$ Heavy Oil

Petrobank's patented THAI™ process has the potential to significantly impact the recovery of heavy oil and bitumen resources worldwide.

WHITESANDS is the first field demonstration of the THAI™ process. The early phase of the project's start-up was initiated in February 2006 in the Canadian oil sands.

THAI™ could potentially recover 70-80% of the bitumen in place in the oil sands versus 20-50% from current in-situ technologies.



Chris J. Bloomer
Vice President Heavy Oil
and Chief Financial Officer

HEAVY OIL BUSINESS UNIT

The Canadian Oil Sands

The Canadian oil sands underlies approximately 140,800 square miles of Alberta, an area larger than the state of Florida, containing the world's largest accumulations of hydrocarbons with an estimated 1.7 trillion barrels of bitumen in place. Using existing technologies, mining and in-situ steaming, an estimated 170 billion barrels of this resource is deemed recoverable, which is approximately 13 percent of the world's oil reserves and second only to Saudi Arabia's 264 billion barrels. Oil sands production is currently one million barrels per day or approximately 40 percent of Canada's oil production and about 10 percent of North American production. Daily production is forecast to rise to between three and five million barrels by 2015, with an estimated \$100 billion to be spent in the oil sands over the same period.

Current Technologies

The bitumen contained in the Canadian oil sands is immobile and can only be produced through open-pit mining where it is close to the surface or, where the bitumen is too deep to mine, through the addition of heat into the reservoir. To date, in-situ recovery using Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) have been utilized to inject steam to heat the reservoir and soften the bitumen so that it can flow to a production well. Steam processes recover from less than 20 percent up to 50 percent of the bitumen in place.

SAGD involves drilling one horizontal well near the bottom of the reservoir and a second horizontal steam injection well three to five metres above the production well. CSS uses one vertical, deviated or horizontal well to inject steam for a period of time, after which the heated bitumen and condensed water is produced using the same well.

Steam processes are energy intensive consuming approximately one mcf of natural gas per barrel of bitumen produced. The environmental impact is also high with large amounts of fresh water required to generate the steam and the associated emission of significant volumes of greenhouse gases from the burning of natural gas.

PETROBANK'S THAI™ PROCESS

Petrobank's THAI™ process is an evolutionary technology that could greatly expand Canada's oil sands reserves, and significantly reduce the energy inputs and environmental impacts associated with the production of the oil sands. THAI™ integrates existing proven technologies and has the potential to create a step change in the recovery of heavy oil and bitumen resources globally.

To field demonstrate the THAI™ process, Petrobank, through its 84 percent owned subsidiary, WHITESANDS Insitu Ltd., is undertaking the WHITESANDS pilot project in the oil sands of Alberta, Canada. The WHITESANDS project is sited on a portion of our 60 sections of oil sands leases in the heart of the oil sands fairway.

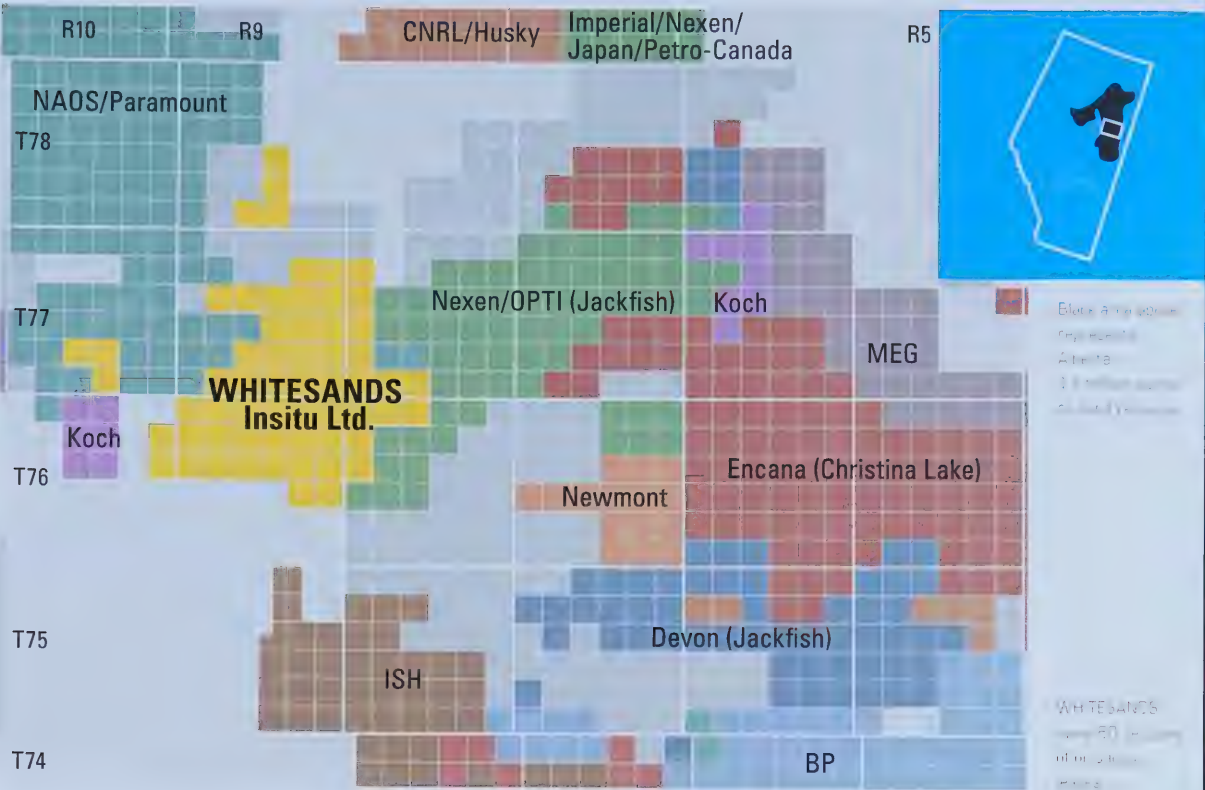
International Activity

While the world's first field test is in the Canadian oil sands, the THAI™ process could be applied to heavy oil reservoirs globally. A key part of Petrobank's business strategy has been to introduce THAI™ to various state oil companies, as well as large international oil companies with interests in heavy oil, particularly in Latin America. To date we have signed technology-sharing agreements with Petrobras, Ecopetrol, PetroEcuador and Petro China. The purpose of these agreements is to permit the sharing of information on reservoirs where THAI™ could potentially be applied, and for Petrobank to conduct reservoir simulations to evaluate those most suitable. We are also in active discussions with several other major oil companies.

In Colombia, in addition to working with Ecopetrol, we have acquired a 100 percent interest in three large Technical Evaluation Areas (TEA) covering 1.5 million acres in the Llanos heavy oil belt. Over the course of 2006, we will evaluate these TEAs for conventional heavy oil potential and the feasibility of undertaking a THAI™ project.

With early success of the WHITESANDS project, Petrobank will seek to rapidly deploy the THAI™ technology globally, both to acquire further resources to develop and to license the technology to third parties.

STRENGTH IN OUR WHITESANDS OIL SANDS LEASES



Installation of the centre pipe rack module for the process facilities at WHITESANDS

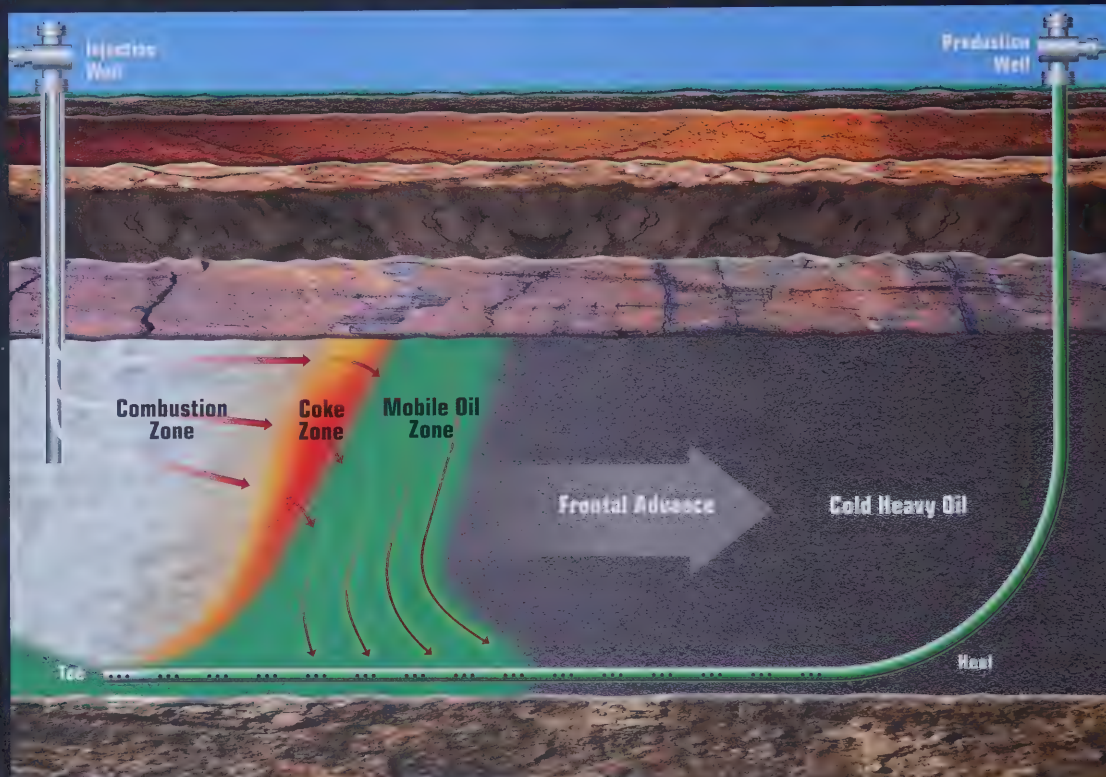
THAI™ process

THAI™ is an evolutionary new configuration for in-situ combustion which combines a horizontal production well with a vertical air injection well placed at the toe.

During the process a high temperature combustion front is created.

Part of the oil in the reservoir is burned, generating heat which reduces the viscosity of the remaining oil allowing it to flow by gravity to the horizontal production well.

The combustion front sweeps the oil from the toe to the heel of the horizontal producing well, recovering up to an estimated 70-80 percent of the original oil-in-place while partially up-grading the crude oil in-situ.



Why THAI™? The potential benefit is sweeping

Higher resource recovery

- Estimated 70-80% recovery of oil in place
- Potentially feasible over a broader range of reservoirs (including: low pressure, thinner, previously steamed, deeper, removal of gas over bitumen; or top and bottom water)

Improved economics

- Lower capital cost – only one horizontal well, minimal steam and water handling facilities
- Lower operating cost – negligible natural gas, minimal steam generation and minimal water processing
- Potential for higher netbacks for partially upgraded product and less diluent use

Lower environmental impact

- Negligible fresh water use
- 50 percent less greenhouse gas emissions

Field-scale simulation

These diagrams are taken from the Computer Modelling Group's "STARS" field-scale numerical simulation model, which is used to evaluate the process under field scale conditions.

Start-up

At start-up the horizontal and vertical wells are steamed for a short period of time to warm the horizontal well and to create mobility around the vertical well to facilitate air injection.

Combustion

Air is injected into the reservoir, auto-igniting the oil creating a high temperature combustion zone (400-700+°C). The hot combusted air contacts the cold oil in front of the combustion zone causing the lighter oil fraction to be mobilized and the heavier fraction to be coked onto the reservoir sand, the coke is the fuel for the ongoing combustion reaction. The light oil and vaporized reservoir water are swept into the horizontal well and to surface. The combustion front moves at the rate of 23 cm a day or 100 meters per year.

Steady State

As air injection continues, the oil drainage front broadens until it reaches the edge of the modeled zone. At this time, a continuous air bank is established and production is expected to be constant at 630 bopd. At steady state, the shape of the oil drainage front is constant, enabling control of the oxygen flux and assuring that the high-temperature oxidation process predominates.

End State

The front edge of the drainage volume has now reached the heel of the horizontal producer. The next set of follow-on horizontal wells can now be drilled. The reservoir is already preheated and the process can continue on in the steady state phase at peak production rates without additional start-up phases. The region behind the burning front is now swept of oil, demonstrating why high recovery factors are expected with the THAI™ process.

The reservoir

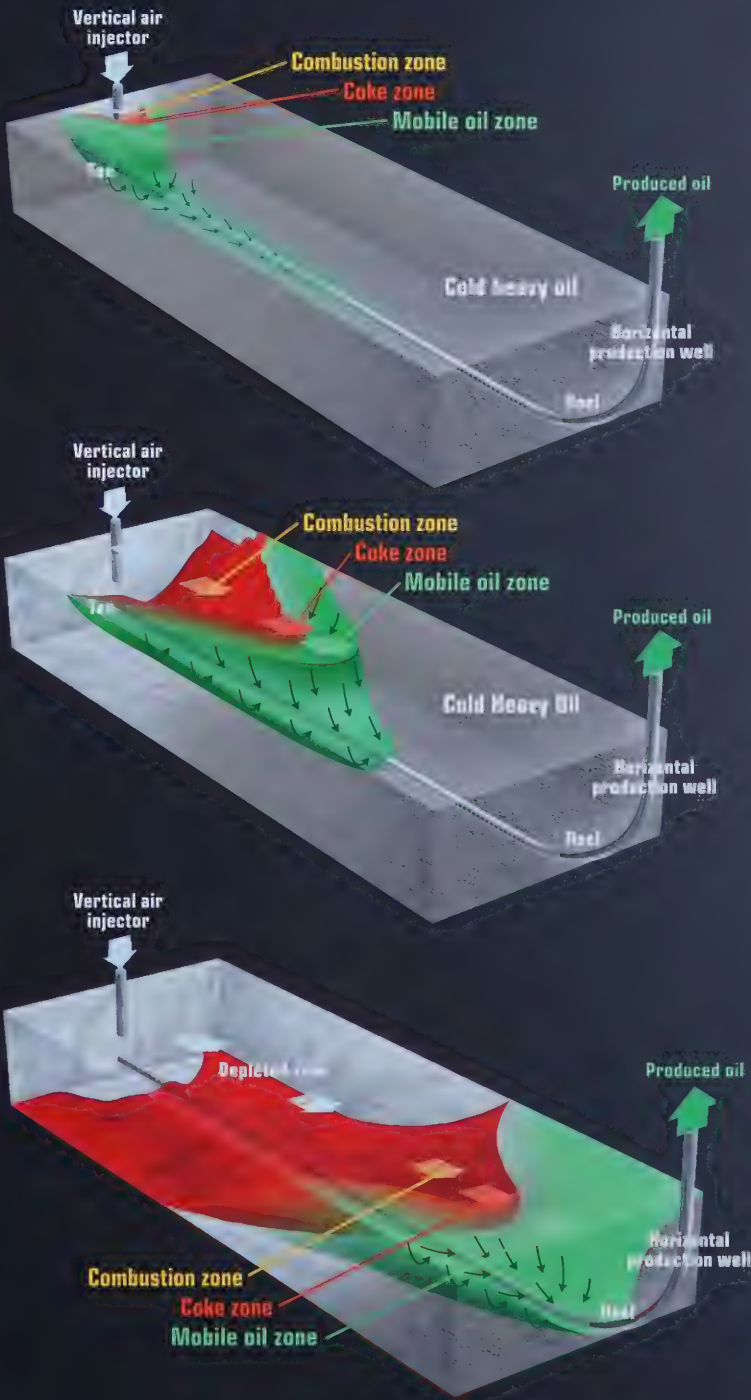
The box represents the volume of the bitumen reservoir that will be swept by the THAI™ process. It has dimensions 500m x 100m x 20m with 80 percent original oil saturation and is representative of one of the pilot wells.

Coke Zone

The red area shows where the heavy fractions (coke) are being deposited in the reservoir. Coke is the fuel for the process.

Mobilized Oil

The green area is where oil saturation has been reduced to 50 percent from 80 percent showing that oil has moved from the zone into the horizontal well.



THAI™ applications – The Canadian oil sands and beyond

HEAVY OIL | THAI™ PROCESS



THAI™ has the potential to operate in lower pressure, lower quality and deeper reservoirs than current steam based processes.

Mining

When oil sands have less than 75 metres of overburden, mining is used to extract the bitumen. Mining requires massive trucking operations to haul the oil sands for processing.

In-situ technologies

Several technologies rely on steam to heat and soften the bitumen underground allowing it to flow to production wells. Both cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are considered economic only in very high-grade oil sands reservoirs, which is only about 10 percent of the resource base, and can only recover 20-50 percent of the bitumen in place.

THAI™ has the potential to recover 70-80 percent of bitumen in place versus 20-50 percent from current in-situ technologies. THAI™ could also be applied to previously steamed reservoirs to recover bitumen left behind by CSS and SAGD.

THAI™ has the potential to operate in reservoirs where other steam-based recovery methods can not.

Unlike current steam-based technologies, THAI™ is not as impacted by the geologic variables found in the oil sands.

Thinner reservoirs can be a target for THAI™ as only one horizontal well is required compared to two horizontal wells with SAGD. THAI™ is not as sensitive to the presence of top or bottom water, which act as heat thief zones, nor the absence of top gas that provides some reservoir pressure.

One of the main geological variables of the oil sands is large shale lenses which act as barriers for steam migration. These shale lenses are less of a concern with THAI™ as the process creates its own pressure regime and operates at very high temperatures, allowing heat to penetrate past these potential barriers.

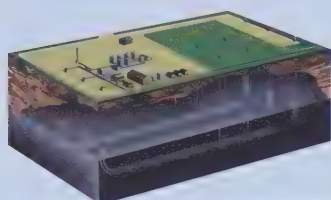
WHITESANDS PILOT PROJECT

The WHITESANDS pilot project is the world's first field-scale demonstration of the THAI™ technology.

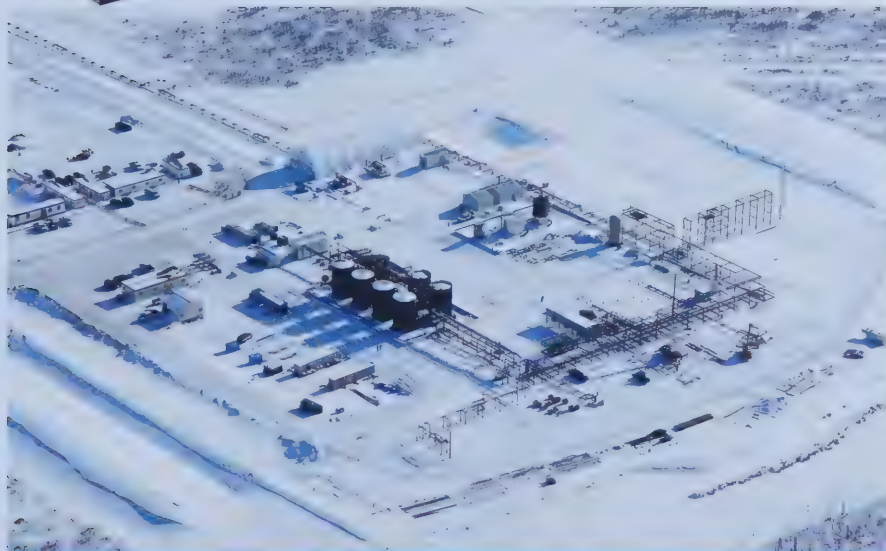
Start-up of the WHITESANDS pilot project began in the first quarter of 2006 with the initiation of steam injection into the center vertical injection well of the three well pairs. This initiated the Pre Injection Heating Cycle (PIHC), which is necessary in order to mobilize the bitumen in the near wellbore portion of the reservoir prior to commencing air injection and initiating combustion. The PIHC is estimated to last approximately 90 days. Oil production is expected to commence as soon as air is injected and combustion is achieved. Each horizontal production well/vertical air injection well pair will be started sequentially. All three well pairs are targeted to be producing via air injection/combustion by the end of 2006.

The pilot project is forecast to produce at a rate of approximately 630 bopd of oil per well, for a total of approximately 1,900 bopd. It is expected that the oil produced will be partially upgraded since the combustion process involves thermally cracking and coking a portion of the oil in-situ and, as the laboratory-scaled reactor tests demonstrated, an upgrade from 10 degrees to 20 degrees API is possible under controlled conditions. However, blending of non-upgraded bitumen in the well bore will likely reduce the upgrading effect of the combustion process in the field application.

The total capital cost of the WHITESANDS pilot project is estimated at \$40 million. Weather delays caused by an exceptionally wet summer in 2005 along with scope changes and the rapid rise in the cost of drilling and construction contributed to cost increases.



WHITESANDS pilot site from design to reality



Pipe rack leading to central injection well

Project timeline

1993

THAI™ process discovered with first successful laboratory scaled reactor test

1997

CAPRI™ discovered

2001

Petrobank acquires initial 45 sections of oil sands leases

2002

First field scale numerical simulations of THAI™

2003

Petrobank acquires THAI™ & CAPRI™ technologies

Oil sands resource evaluated with seismic & drilling

Independent evaluation assigns 1.3 billion barrels of bitumen resource to WHITESANDS – THAI™ pilot project

Pilot design commences

2004

WHITESANDS regulatory approval received

Detailed engineering design begins

Pilot site selected

Additional drilling confirms resource quality on pilot site

Civil engineering commences

2005

Richardson Financial Group acquires 16% interest in WHITESANDS Insitu Ltd.

Secured non-dilutionary \$9 million Technology Partnerships Canada financing

Acquired additional four sections of oil sands leases

Final design and engineering completed

Three horizontal production/vertical injection well pairs drilled along with 12 observation wells

Facilities construction commences

2006

March

Pre Ignition Heating Cycle (PIHC) commences

Acquired additional 11 sections of oil sands leases

2006 Plan

Finalize facilities construction

Initiate air injection/combustion on first well pair in June

Sequentially initiate PIHC in remaining two well pairs

All three well pairs on combustion by year-end

Intellectual Property

Research and development activities were consolidated under Petrobank's 100 percent-owned subsidiary, Archon Technologies Ltd. (Archon), in 2005 with the establishment of our own independent laboratory facilities. In 2005 Archon filed a worldwide patent, "Oilfield Enhanced In-situ Combustion Process – U.S. registration #33,105", which is an enhancement to the original THAI™ process allowing higher well bore temperatures, resulting in increased production rates and the flexibility to inject air at higher rates.

Ongoing activities include the advancement of CAPRI™, another key technology, which adds a catalyst around the horizontal production well to increase the in-situ upgrading effect of THAI™. We expect to test CAPRI™ early on in the WHITESANDS project.

In 2005 Archon added significant new reservoir simulation capacity with the acquisition of a 64-bit computer. We can model any reservoir in the world and can conduct multi-well evaluations and history match the performance of the WHITESANDS Insitu Ltd. project to our reservoir simulation modeling. In addition, we expect this capability to lead to significant new intellectual property and new patents.

Financing Activities

In April 2005, we closed a transaction with Richardson Capital Limited, where they invested \$14 million to acquire a 16 percent interest in WHITESANDS Insitu Ltd. They also acquired three million common shares of Petrobank bringing aggregate gross proceeds to \$23.8 million. Petrobank retained an 84 percent interest in WHITESANDS and 100 percent of all international THAI™ development opportunities.

In April 2005 we also announced a non-dilutionary \$9 million investment commitment by Technology Partnerships Canada (TPC) towards the initial construction of the WHITESANDS pilot project; the pilot's operating costs for five years, and research and development costs to further advance the THAI™ technology. TPC is a key federal government instrument for advancing research and development toward commercialization. Working in partnership with innovative companies across Canada, TPC shares in the cost of private sector technology projects in aerospace and defense, environmental technologies, and in enabling technologies such as information and communications technologies and biotech.

These transactions bring the total third party financing of the project to \$32.8 million, which funded the majority of the initial construction costs of the pilot.

ENVIRONMENT, COMMUNITY RELATIONS AND SECURITY

Our Heavy Oil Business Unit through the WHITESANDS project is proactive in its communication with the local communities of Conklin and the Janvier Nation. There is regular dialogue with the community providing updates about project operations and opportunities for discussion of unique community issues where we might play a supporting role. As a matter of practice, local contractors with the appropriate skills are contracted to work on the project. Health, safety and environmental management are integral to the WHITESANDS operation and we meet or exceed all government requirements.

LOOKING AHEAD

Our 2006 plan:

The WHITESANDS project will complete a rolling start-up of the remaining two well pairs and facilities through 2006. Upon completion of the PIHC and commencement of air injection in the first well pair, the remaining two well pairs will sequentially startup.

In October 2005 and February 2006 we acquired an additional 15 sections of new oil sands leases. An updated resource evaluation will be completed by the end of the first quarter of 2006 which should show a significant increase in our in-place bitumen resource.

A 17-square kilometre 3-D seismic survey was initiated on our lands and one additional oil sands exploration well was completed during the first quarter of 2006. We will evaluate the 3-D survey and drill several additional oil sands exploration wells in 2006.

We will solidify our international focus, through Petrominerales, with the evaluation of three heavy oil blocks in Colombia while advancing relationships on other international heavy oil prospects.

Research and development within Archon Technologies Ltd. is advancing and one additional patent was applied for in the first quarter of 2006. We will continue to evaluate enhancements to THAI™ and CAPRI™ as well as complementary technologies.



Vertical injection wells with pipe rack the centre well was put on steam injection in early March 2006

OPERATIONS STATISTICAL REVIEW

Land

The Canadian Business Unit currently holds 379,000 (313,000 net) acres of undeveloped land, including 154,000 fee-title acres. Petrobank owns the underlying mineral rights in perpetuity on these fee-title lands. The Heavy Oil Business Unit's oil sands leases at WHITESANDS now total 38,400 acres. In Colombia, our Orito and Neiva incremental production blocks cover 45,000 gross acres, and exploration blocks and TEAs cover 2,514,000 acres.

Land Summary (thousands of acres)

At December 31, 2005

	Developed		Undeveloped		Total		Average
	Gross	Net	Gross	Net	Gross	Net	WI%
Alberta	57	35	122	90	179	125	70%
Saskatchewan	2	1	175	162	177	163	92%
Other	–	–	82	61	82	61	74%
Canadian Business Unit	59	36	379	313	438	349	80%
WHITESANDS ⁽¹⁾	–	–	31	31	31	31	100%
Colombia	45	35	2,514	2,514	2,559	2,549	100%
Total Company	104	71	2,924	2,858	3,028	2,929	97%

(1) Increased oil sands land holdings to 38,400 acres early in 2006.

2005 Drilling Program

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Oil	8.0	5.7	5.0	2.0	13.0	7.7
Natural gas	7.0	4.3	60.0	42.6	67.0	46.9
Successful	15.0	10.0	65.0	44.6	80.0	54.6
Dry	3.0	3.0	–	–	3.0	3.0
Total Canada	18.0	13.0	65.0	44.6	83.0	57.6
Success rate	83%	77%	100%	100%	96%	95%
Colombia						
Oil	1.0	0.8	2.0	1.6	3.0	2.4
Dry	–	–	–	–	–	–
Total Colombia	1.0	0.8	2.0	1.6	3.0	2.4
Success rate	100%	100%	100%	100%	100%	100%

Production

The following table sets forth the Company's average daily production volumes, by major producing region, for the three and twelve month periods ended December 31, 2005.

Average Daily Production

	Light/Medium Oil and NGL (bbl)		Heavy Oil (bbl)		Gas (mcf)		Total (boe)	
	2005 Average	Q4 2005	2005 Average	Q4 2005	2005 Average	Q4 2005	2005 Average	Q4 2005
Canada								
Jumpbush	32	30	–	–	8,841	11,821	1,506	2,000
Red Willow	165	185	–	–	1,530	1,770	420	480
Others	240	424	15	23	1,439	1,201	494	647
Total Canada	437	639	15	23	11,810	14,792	2,420	3,127
Colombia – Orito	685	627	–	–	–	–	685	627
Colombia – Neiva	346	328	–	–	–	–	346	328
Total Colombia	1,031	955	–	–	–	–	1,031	955
Total Company	1,468	1,594	15	23	11,810	14,792	3,451	4,082

Working Interest Reserves – Forecast Prices

Petrobank's Canadian reserves evaluation at December 31, 2005 was performed by Sproule Associates Limited (Sproule). The Colombian reserves evaluation as at December 31, 2005, was performed by DeGolyer and MacNaughton (D&M). No reserves have been recorded on the Company's exploration blocks in Colombia or on the Company's Canadian oil sands leases.

	Natural Gas (mmcf)	Light and Medium Oil (mbbl)	Heavy Oil (mbbl)	NGL (mbbl)	Canada	Colombia
					Total (mboe)	Light and Medium Oil (mbbl)
Developed producing	19,135	244	4	9	3,445	2,171
Total proved	40,930	467	4	80	7,372	9,582
Proved + probable	63,524	867	26	155	11,635	16,085
Proved + probable + possible	86,180	1,258	335	231	16,188	22,263

Net Reserve Reconciliation - Forecast Prices

	Canada (mboe)		Colombia (mbbl)	
	Total Proved	Proved + Probable	Total Proved	Proved + Probable
December 31, 2004 reserves	4,952	9,151	5,643	9,465
2005 production net of royalty income	(771)	(771)	(376)	(376)
Net additions	3,191	3,255	4,315	6,996
December 31, 2005 reserves	7,372	11,635	9,582	16,085
Increase in reserves	49%	27%	70%	70%
Production replacement	414%	422%	1,148%	1,861%

Net Present Value – Before Tax – Forecast Prices

As at December 31, 2005

	Canada (\$ millions)				Colombia (US\$ millions)			
	0%	5%	10%	15%	0%	5%	10%	15%
Developed producing	137.5	116.1	102.6	93.0	80.2	64.5	53.6	45.7
Total proved	229.0	182.4	153.1	132.9	278.8	209.3	160.8	125.7
Proved + probable	352.9	256.8	204.3	171.2	467.7	351.8	271.0	212.8
Proved + probable + possible	491.6	332.6	254.8	208.8	690.1	508.2	384.7	297.6

Net Present Value – After Tax – Forecast Prices

As at December 31, 2005

	Canada (\$ millions)				Colombia (US\$ millions)			
	0%	5%	10%	15%	0%	5%	10%	15%
Developed producing	135.1	114.7	101.5	92.1	76.0	62.1	52.3	44.9
Total proved	200.2	161.9	137.5	120.4	220.5	168.6	131.5	104.1
Proved + probable	282.8	211.1	171.0	145.2	343.9	260.9	202.2	159.2
Proved + probable + possible	374.8	260.9	203.7	169.0	488.5	362.5	275.9	214.2

2005 Capital Expenditures by Business Unit

(\$000s)	Canada	Colombia	Heavy Oil	Total
Drilling and completions	\$ 24,551	\$ 18,683	\$ 13,430	\$ 56,664
Facilities and equipment	11,802	293	13,164	25,259
Land	4,920	-	3,405	8,325
Seismic	2,623	5,095	8	7,726
Workovers and other	3,191	14,353	2,169	19,713
Pilot design and engineering	-	-	465	465
Total capital expenditures	47,087	38,424	32,641	118,152
Government assistance	-	-	(5,864)	(5,864)
Investment tax credits	-	-	(4,137)	(4,137)
Net capital expenditures	\$ 47,087	\$ 38,424	\$ 22,640	\$ 108,151

Finding and Development Costs (F&D)

	2005	2004	Three-Year Average
Canada			
Capital expenditures (\$000s)	47,087	30,429	37,580
Change in future costs to develop (\$000s)			
Proved	14,873	6,243	8,504
Proved plus probable	16,682	11,493	11,778
Total costs (\$000s)			
Proved	61,960	36,672	46,084
Proved plus probable	63,769	41,922	49,358
Net reserve additions (mboe)			
Proved	3,191	4,218	2,886
Proved plus probable	3,255	7,382	4,418
F&D costs (\$ per boe)			
Proved	19.42	8.69	15.97
Proved plus probable	19.59	5.68	11.17
Colombia			
Capital expenditures (\$000s)	38,424	13,906	41,224
Change in future costs to develop (\$000s)			
Proved	61,727	11,294	18,631
Proved plus probable	93,470	23,649	34,222
Total costs (\$000s)			
Proved	100,151	25,200	59,855
Proved plus probable	131,894	37,555	75,446
Net reserve additions (mbbl)			
Proved	4,315	2,071	2,073
Proved plus probable	6,996	3,089	3,612
F&D costs (\$ per bbl)			
Proved	23.21	12.17	28.87
Proved plus probable	18.85	12.16	20.89

MANAGEMENT'S DISCUSSION AND ANALYSIS

Summary of Annual Results

	2005	2004	2003
Financial ⁽¹⁾			
(\$000s, except where noted)			
Oil and natural gas revenue	65,081	73,377	67,504
Cash flow from operations ⁽²⁾	29,152	23,397	29,258
Per share – basic (\$)	0.50	0.43	0.45
Per share – diluted (\$)	0.49	0.43	0.44
Net income (loss)	12,808	833	(23,339)
Per share – basic (\$)	0.22	0.02	(0.49)
Per share – diluted (\$)	0.21	0.02	(0.49)
Capital expenditures	118,152	47,901	116,060
Property dispositions	-	143,027	20,448
Total assets	260,982	205,392	257,004
Net debt ^{(3) (4)}	60,808	35,183	150,955
Common shares outstanding, end of year (000s)			
Basic ⁽⁴⁾	63,220	54,956	54,503
Diluted	68,451	59,758	59,599
Operations ⁽⁵⁾			
Canadian operating netback (\$/boe except where noted)			
Oil and NGL revenue (\$/bbl) ⁽⁶⁾	60.96	25.42	28.48
Natural gas revenue (\$/mcf) ⁽⁶⁾	8.09	5.99	6.44
Oil and natural gas revenue ⁽⁶⁾	50.84	31.84	32.42
Royalties	10.46	7.17	6.56
Production expenses	6.05	7.07	7.48
Transportation expenses	0.98	0.94	0.82
Operating netback	33.35	16.66	17.56
Colombian operating netback (\$/bbl)			
Oil revenue	53.62	43.70	32.22
Royalties	4.29	3.51	2.56
Production expenses	9.49	7.67	10.48
Operating netback	39.84	32.52	19.18
Average daily production			
Canada – oil and NGL (bbls)	452	1,732	2,840
Canada – natural gas (mcf)	11,810	16,196	10,821
Total Canada (boe)	2,420	4,431	4,643
Colombia – oil (bbls)	1,031	1,359	1,068
Total Company (boe)	3,451	5,790	5,711

(1) The financial information for 2004 and 2003 has been restated for changes in accounting policies.

(2) Calculated based on cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled.

(3) Includes working capital (deficiency) and subordinated notes.

(4) On February 7, 2006, the Company issued an additional 2,597,403 common shares bringing the total number outstanding to 65,817,124, for gross proceeds of \$33.4 million in connection with a public offering and secondary listing on the Oslo stock exchange.

(5) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent ("boe").

(6) Canadian sales prices are shown after hedging costs.

The following Management's Discussion and Analysis ("MD&A") is dated March 10, 2006 and should be read in conjunction with the Company's consolidated financial statements and accompanying notes for the years ended December 31, 2005 and 2004. Additional information for the Company, including the Annual Information Form ("AIF"), can be found at www.sedar.com. In addition to historical information, the MD&A contains "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are generally identifiable by terms such as anticipate, believe, budget, intend, estimate, expect, outlook, plan or other similar words, and include future capital investment plans. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; the ability to economically test, develop and utilize the Company's patented technologies, the feasibility of the technologies; and other factors, many of which are beyond the control of the Company. There is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("mcf") of natural gas is equal to one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are not considered measures under Canadian Generally Accepted Accounting Principles ("GAAP"), such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital and asset retirement obligations settled. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Highlights

- Effective March 31, 2005 Technology Partnerships Canada ("TPC") announced their commitment to invest up to \$9 million towards the development and field demonstration of the Company's THAI™ technology at the WHITESANDS pilot project. TPC's investments are made quarterly based on 20.134 percent of eligible expenditures.
- On April 12, 2005, the Company closed a \$23.75 million financing to fund the WHITESANDS pilot project. The investor acquired a 16 percent interest in WHITESANDS Insitu Ltd. and also acquired three million common shares of Petrobank. Collectively, these proceeds will be used to fund a significant portion of the construction costs of the WHITESANDS pilot project.
- During 2005, the Company's Latin American Business Unit negotiated contracts on five exploration blocks and five Technical Evaluation Areas ("TEA") covering a total of 2,480,530 acres in the Llanos Basin and 33,671 acres in the Putumayo Basin. In total these blocks cover 2,514,201 acres (3,928 square miles).
- On October 20, 2005 the Company issued four million shares at a price of \$9.65 per common share for gross proceeds of \$38.6 million.
- During 2005, the Company repurchased a total of \$50.5 million principal amount of Petrobank subordinated notes reducing the total principal amount outstanding to \$49.9 million.
- Despite disposing of 49 percent of production during 2004, cash flow from operations increased by 25 percent in 2005 to \$29.2 million.
- Recorded net income of \$12.8 million compared to \$0.8 million a year earlier. On a per diluted share basis, net income increased 950 percent to \$0.21 in 2005 from \$0.02 in 2004.
- Capital expenditures totaled \$118.2 million: \$47.1 million in Canada; \$38.4 million in Latin America; and \$32.6 million in the Heavy Oil Business Unit.
- In February 2006 the Company issued 2.6 million common shares for gross proceeds of \$33.4 million (\$30.6 million net of costs) in connection with a public offering and secondary listing on the Oslo stock exchange.

Major Projects

WHITESANDS THAI™ Pilot Project

At WHITESANDS, the Company invested \$28.4 million in 2005 on constructing the THAI™ pilot project and \$0.8 million on drilling three stratigraphic wells. In October 2005 the Company acquired four sections of new oil sands acreage in close proximity to the Company's existing leases for \$3.4 million and another 11 sections contiguous to the Company's existing leases in February 2006 for \$20.4 million. This brings the Company's total oil sands land holdings to 60 sections or 38,400 acres.

The WHITESANDS pilot project is targeting start-up of initial air injection in the second quarter of 2006 and pilot project wells and construction costs are expected to total approximately \$40 million, 33 percent or \$10 million above the Company's initial estimate of \$30 million. Project costs increased as a result of scope changes made in the final engineering design and a general escalation of costs within the industry. Estimated costs remaining to complete construction are approximately \$10 million. The project's three horizontal production wells and vertical air injection well pairs were drilled in 2005 along with 12 observation wells, which will monitor the process in-situ. Facilities construction was more than 60 percent complete at the end of the year and is expected to be fully commissioned in April 2006. The Company started the Pre Ignition Heating Cycle ("PIHC") with steam injection into the first vertical air injection well in early March 2006. The PIHC phase is

programmed to continue for approximately 90 days with steam injection in the first vertical and horizontal well pair. Air injection in this first well pair will commence when the bitumen around the vertical air injection well has been sufficiently mobilized. Once combustion is initiated from the first well pair, the PIHC phase for the second well pair will begin. All three well pairs are expected to be on production by the end of 2006. The Company is also evaluating the potential to initiate a test of our CAPRI™ technology later in 2006.

Results of Operations

Significant Transactions

The Company disposed of several Canadian properties throughout 2004 for total proceeds of \$143.0 million. The largest sale closed in December 2004 for proceeds of \$96.1 million. A pre-tax gain of \$16.6 million was recorded on this transaction. Proceeds from the dispositions were used to eliminate bank debt, repurchase a portion of the outstanding subordinated notes, and fund a significant portion of the 2005 capital expenditure program. Production from the disposed properties accounted for 64 percent of the Company's Canadian production and 49 percent of the Company's consolidated production in 2004.

On April 12, 2005 the Company sold a 16 percent interest in its previously wholly-owned subsidiary, WHITESANDS Insitu Ltd. for proceeds net of issuance costs totaling \$12.7 million resulting in a pre-tax gain of \$4.7 million.

Revenue

Despite selling 49 percent of 2004 production, revenue only decreased 11 percent to \$65.1 million in 2005 (2004 - \$73.4 million). Average production decreased by 40 percent to 3,451 boe per day ("boepd"), while average sales prices increased by 49 percent to \$51.67 per boe.

Average Daily Production

	Q4 2005	2005	2004
Canada – light / medium oil and NGL (bbls)	639	437	1,170
Canada – conventional heavy oil (bbls)	23	15	562
Canada – natural gas (mcf)	14,792	11,810	16,196
Total Canada (boe)	3,127	2,420	4,431
Colombia – oil (bbls)	955	1,031	1,359
Total Company (boe)	4,082	3,451	5,790

In 2005, Canadian natural gas production decreased by 27 percent to 11.8 mmcf per day ("mmcfpd") from 16.2 mmcfpd in 2004. The decrease was a result of major property dispositions in 2004 that accounted for approximately 9.0 mmcfpd of production in 2004. Excluding these major dispositions, natural gas production in the fourth quarter of 2005 increased by approximately 50 percent or 5.0 mmcfpd over the same three month period a year earlier. In 2006, the Company plans to drill approximately 80 wells at Jumpbush which is expected to add to the natural gas production gains that were experienced through 2005.

Canadian light/medium oil and natural gas liquids ("NGL") production averaged 437 barrels per day ("bpd") in 2005, an expected decrease from the 1,170 bpd produced in 2004 due to major property dispositions throughout 2004. All of the Company's Canadian conventional heavy oil production was sold late in the fourth quarter of 2004, but drilling at Macklin, Saskatchewan added heavy oil production in the third quarter of 2005. Conventional heavy oil production should continue to increase in 2006 as additional wells are drilled at Macklin.

Canadian production in 2005 includes 322 boepd (2004 – 269 boepd) of royalty income production from the Company's fee-title lands, which are included in the Company's net reserves but not working interest reserves.

Colombian oil production decreased by 24 percent to 1,031 bpd in 2005 from 1,359 bpd in 2004. Production declined to 955 bpd in the fourth quarter of 2005 due to natural declines and wells being off line in order to complete well interventions at Orito. Colombian production increased early in 2006 to approximately 1,400 bpd.

Average Benchmark Prices

	Q4 2005	2005	2004
WTI crude oil (US\$/bbl)	60.05	56.70	41.40
WTI crude oil (Cdn\$/bbl)	70.47	68.56	53.91
NYMEX natural gas (US\$/mmbtu) ⁽¹⁾	12.97	8.62	6.14
US\$/Cdn\$ exchange rate	0.85	0.83	0.77

(1) Prices quoted are near-month contract prices for settlement during the next month.

Increases in U.S. dollar-denominated benchmark commodity prices during 2005 were partially offset by the appreciation of the Canadian dollar. Oil prices have remained strong in the first quarter of 2006 and for the year are expected to average US\$63.86 per barrel WTI. Natural gas prices have declined primarily as a result of a warm winter in North America, and are expected to average US\$7.70 per mmbtu NYMEX in 2006, including prices currently forecast in the futures market. The US\$/Cdn\$ exchange rate is currently forecast to be \$0.86 in 2006.

Price Risk Management

All of Petrobank's financial commodity price contracts expired at the end of 2004 contributing significantly to increased realized prices in 2005. The Company's only remaining fixed price sales contract is a long-term physical natural gas sales contract, a description of which is included in Note 14 to the Consolidated Financial Statements, "Financial Instruments and Financial Risk Management".

Realized Prices

The average Canadian oil and NGL price per barrel received in 2005 was \$60.96, an increase of 140 percent from the 2004 price of \$25.42. The significant increase is due to increases in benchmark prices, disposition of all the Company's heavy oil production in December 2004, and hedging losses on contracts that expired at the end of 2004. The price received in 2005 represents a US\$6.86 discount to average WTI prices for the year compared to a US\$9.78 discount to WTI before the impact of hedges in 2004. The average discount decreased primarily as a result of less heavy oil production reducing the negative impact of Canadian heavy crude oil differentials.

The average natural gas price received in 2005 was \$8.09 per mcf, a 35 percent increase from the \$5.99 per mcf received in 2004. The fourth quarter price averaged \$10.36 per mcf, 79 percent above the average price for the same quarter a year earlier. The increases were primarily the result of higher commodity prices and the negative impact of financial hedging contracts in 2004. Natural gas prices reflect the negative impact of the Company's long-term physical natural gas sales contract. In 2004, the natural gas price was also impacted by a natural gas price collar on 10,000 mcfpd with a ceiling AECO price of \$6.27 per mcf. This contract expired on December 31, 2004.

Oil sales prices in Colombia averaged US\$44.27 per barrel in 2005, 32 percent higher than the 2004 average of US\$33.58 per barrel. In 2005, the average discount to WTI was US\$12.43 per barrel, or 22 percent of WTI, compared to the discount of US\$7.82 per barrel, or 19 percent of WTI, in 2004. Fourth quarter prices averaged US\$44.74 per barrel, representing a discount to WTI of US\$15.31 per barrel, or 25 percent of WTI, compared to US\$38.05 per barrel and a discount of US\$10.23, or 21 percent a year earlier. The average discount to WTI increased year-over-year due to the Orito marketing agreement that was amended in December 2004 to account for WTI prices above US\$35.00 per barrel. Prior to this time, the differential was fixed at WTI prices above US\$30.00.

Royalties

Consolidated royalty expense decreased to \$10.9 million from \$13.4 million in 2004. Canadian royalties as a percentage of revenue decreased to 21 percent in 2005 compared to 23 percent in 2004. Gains and losses on certain hedging contracts do not impact royalties. Accordingly, hedging losses in 2004 resulted in a higher effective royalty rate. The Company anticipates Canadian royalty rates to be approximately 23 percent in 2006. Colombian royalties are fixed at a rate of eight percent until Petrobank's net production per field exceeds 5,000 bpd.

Production Expenses

Consolidated production expenses decreased by 42 percent to \$8.9 million in 2005 from \$15.3 million in 2004. Production expenses per unit of production in Canada were \$6.05 per boe in 2005, a 14 percent decrease from \$7.07 per boe in 2004. The reductions are primarily a result of the disposition of high cost properties in 2004. The Company anticipates production expenses in Canada to decrease in 2006 to less than \$6.00 per boe with the continued addition of low cost production, mainly at Jumpbush.

Production expenses in Colombia averaged \$9.49 per barrel during 2005, a 24 percent increase from the 2004 average of \$7.67 per barrel. Ecopetrol, the state oil company and Petrobank's partner, is responsible for primary production operations at Orito and Neiva at a fixed operating fee of US\$3.91 per barrel and US\$2.13 per barrel respectively. The increase in Colombian per unit operating costs is primarily a result of the fixed nature of internal costs combined with lower production volumes. The Company anticipates production expenses in Colombia to decrease in 2006 to less than \$8.00 per barrel with the addition of new production at Orito.

General and Administrative Expenses

Consolidated general and administrative expenses increased seven percent in 2005 to \$7.6 million from \$7.1 million in 2004. In Canada, general and administrative expenses decreased slightly to \$4.2 million from \$4.5 million a year earlier. A general increase in Colombian staffing costs caused general and administrative expenses to increase from \$2.6 million in 2004 to \$3.5 million in 2005.

Stock-Based Compensation

Stock-based compensation expense increased to \$1.2 million in 2005 from \$0.3 million in 2004. The calculation of this non-cash expense is determined based on the fair value of stock options and deferred common shares granted. At higher common share prices the calculated fair value of new grants increases along with the corresponding stock-based compensation expense.

Interest on Bank Debt

Interest on bank debt was nil in 2005, down from \$1.2 million in 2004. The Company was drawn on its bank facility for the majority of 2004 until proceeds from a major property disposition were used to eliminate bank debt late in the fourth quarter.

Interest on Subordinated Notes

The Company repurchased 50 percent (\$50.5 million face value) of the outstanding subordinated notes throughout 2005. As a result, interest on subordinated notes decreased to \$8.4 million in 2005, down from \$11.5 million in 2004.

Depletion, Depreciation and Accretion

Consolidated depletion, depreciation and accretion expense decreased to \$16.4 million in 2005 from \$33.4 million in 2004. On a unit-of-production basis, the Canadian rate was \$10.65 per boe compared to \$14.29 per boe a year earlier. The rate decreased as a result of reserve additions generated from the late 2004 and 2005 drilling programs. The rate in Colombia decreased to \$18.53 per barrel from \$20.50 per barrel in the prior year due to reserve additions primarily at Orito.

Other Income (Expense)

Due primarily to interest income received on cash balances throughout the year, other income increased to \$0.8 million in 2005 from an expense of \$1.3 million in 2004. Expenses in 2004 related mainly to foreign exchange losses resulting from an appreciation in the Canadian dollar, combined with increasing U.S. dollar denominated working capital balances driven by higher commodity prices and lower Colombian capital expenditures.

Capital Taxes

Capital tax expense of \$2.0 million in 2005 was higher than the \$1.5 million incurred a year earlier. The current tax relates to Large Corporations Tax in Canada and presumptive income taxes in Colombia that are based on debt and equity levels. Colombian presumptive income taxes can be recovered against income taxes payable in future periods and can be carried forward for eight years. Petrobank does not anticipate a cash income tax liability in either Canada or Colombia for at least the next two years.

Future Income Taxes

The Company recorded a \$0.6 million future income tax expense in 2005 compared to \$2.7 million in 2004. The 2005 expense was lower mainly as a result of recording a \$16.6 million gain on properties that were sold in 2004.

Net Income

Despite the disposition of a significant number of properties and the recognition of a \$16.6 million gain in 2004, net income increased to \$12.8 million from \$0.8 million in 2004. On a per diluted share basis, net income increased to \$0.21 in 2005 from \$0.02 in 2004. Profitability increased based on a number of factors: the properties retained after the 2004 dispositions offer higher netbacks, commodity prices increased sharply, financial hedges expired at the end of 2004, depletion decreased as a result of significant 2005 reserve additions, and a gain on the sale of a minority interest in the Company's WHITESANDS Insitu Ltd. subsidiary recorded in 2005.

Cash Flow from Operations

Despite the 2004 property dispositions, cash flow from operations increased by 25 percent to \$29.2 million in 2005 from \$23.4 million in 2004. On a per diluted share basis, cash flow increased by 14 percent to \$0.49 from \$0.43 a year earlier. The increase is a result of higher netbacks on retained properties, significantly higher commodity prices, and financial hedging contracts that expired at the end of 2004.

Capital Expenditures

Years ended December 31,	2005	2004
Business Unit		
Canada	\$ 47,087	\$ 30,428
Latin America	38,424	13,906
Heavy Oil	32,641	3,567
Total	\$ 118,152	\$ 47,901

Canadian Business Unit expenditures were primarily focused on drilling, completions and facilities at the Company's Jumpbush property. Latin American expenditures related to drilling three wells at Orito and performing well interventions at Orito, along with the first phase of work commitments on our new exploration blocks, which commenced late in 2005. Expenditures in the Heavy Oil Business Unit related to construction of the WHITESANDS pilot project and the acquisition of additional oil sands leases.

Canadian activity in 2006 is expected to include drilling approximately 80 wells at Jumpbush (70 – 100 percent working interest) and up to an additional 40 wells in connection with the Company's development and exploration programs at Innes, Macklin, Red Willow, Little Bow and Princeton.

Latin American activity will focus on bringing production on line from three wells drilled at Orito in 2005, drilling up to six wells at Orito and up to 10 wells at Neiva, fracture stimulations at Orito and Neiva, and completing initial work programs on the Company's recently acquired exploration acreage.

Heavy Oil activity in 2006 includes the acquisition of oil sands leases, completing facilities construction and start-up of the WHITESANDS pilot project in the first half of 2006, and potentially testing the Company's CAPRI™ technology later in the year.

Summary of Quarterly Results

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial (\$000s except where noted) ⁽¹⁾								
Oil and natural gas revenue	22,510	17,983	13,206	11,382	17,028	18,700	18,175	19,474
Cash flow from operations ⁽²⁾	12,304	8,877	4,575	3,396	4,388	6,166	6,215	6,628
Per share - basic (\$)	0.20	0.15	0.08	0.06	0.08	0.11	0.11	0.12
- diluted (\$)	0.19	0.15	0.08	0.06	0.08	0.11	0.11	0.12
Net income (loss)	5,184	3,170	4,702	(248)	6,630	(1,727)	(1,822)	(2,248)
Per share - basic and diluted (\$)	0.08	0.05	0.08	-	0.12	(0.03)	(0.03)	(0.04)
Capital expenditures	58,436	32,094	16,842	10,780	14,272	8,921	9,995	14,713
Property dispositions	-	-	-	-	100,166	550	4,174	38,137
Operations								
<i>Canadian operating netbacks by product</i> ⁽³⁾								
Light/medium oil and NGL sales price (\$/bbl)	63.46	66.45	63.60	47.59	21.05	27.03	29.54	27.50
Royalties	13.82	14.12	13.94	9.76	10.18	9.79	8.93	8.97
Production expenses	7.92	7.05	10.82	9.99	9.11	6.78	7.14	6.81
Operating netback	41.72	45.28	38.84	27.84	1.76	10.46	13.47	11.72
Heavy oil sales price (\$/bbl)	31.10	52.14	-	-	15.96	26.95	22.36	24.46
Royalties	0.72	0.91	-	-	4.36	5.31	3.29	3.45
Production expenses	15.28	5.95	-	-	9.89	9.08	10.69	8.52
Operating netback	15.10	45.28	-	-	1.71	12.56	8.38	12.49
Natural gas sales price (\$/mcf)	10.36	8.25	6.60	6.08	5.80	6.13	5.99	6.09
Royalties	2.15	1.60	1.45	1.19	1.18	1.10	1.08	1.20
Production expenses	0.70	0.91	1.10	1.02	1.18	1.08	0.94	1.06
Transportation expenses	0.11	0.23	0.21	0.29	0.23	0.23	0.30	0.28
Operating netback	7.40	5.51	3.84	3.58	3.21	3.72	3.67	3.55
Oil equivalent sales price (\$/boe)	62.21	53.07	42.63	38.30	29.90	33.09	32.22	32.18
Royalties	13.00	10.41	9.35	7.59	7.53	7.20	6.79	7.15
Production expenses	5.07	5.81	7.12	6.76	7.81	6.90	6.77	6.82
Transportation expenses	0.53	1.08	1.13	1.43	0.93	0.85	1.02	0.97
Operating netback	43.61	35.77	25.03	22.52	13.63	18.14	17.64	17.24
<i>Colombian operating netback (\$/bbl)</i>								
Oil sales price	52.50	60.24	52.34	49.13	46.45	48.69	45.62	36.63
Royalties	4.20	4.82	4.19	3.93	3.71	3.96	3.62	2.93
Production expenses	10.08	9.41	10.09	8.46	7.08	7.10	8.53	7.89
Operating netback	38.22	46.01	38.06	36.74	35.66	37.63	33.47	25.81
<i>Average daily production</i>								
Canada - light/medium oil and NGL (bbls)	639	514	273	317	993	1,065	1,288	1,332
Canada - heavy oil (bbls)	23	37	-	-	424	564	562	703
Canada - natural gas (mcf)	14,792	11,485	11,245	9,662	17,880	16,231	14,592	16,069
Total Canada (boe)	3,127	2,465	2,147	1,927	4,397	4,334	4,282	4,713
Colombia - oil (bbls)	955	1,073	1,024	1,072	1,155	1,229	1,354	1,702
Total Company (boe)	4,082	3,538	3,171	2,999	5,552	5,563	5,636	6,415

(1) 2004 periods restated for a change in accounting policy.

(2) Calculated based on cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled.

(3) Sales prices are shown after hedging costs. The hedging costs relating to oil sales were net against the Canadian light/medium oil and NGL sales price, except for the Company's 300 bopd fixed price crude oil contract (WTI - US\$27.74) that was net against the heavy oil sales price in 2004. The majority of these hedges expired on December 31, 2004.

Major factors impacting quarterly results:

- Disposed of Wapella, Epping, Edmonton, Swimming, Wetaskiwin, Nevis, Rainbow, Shekilie, Lashburn, Eyehill, and Red Jacket properties during 2004 for total proceeds of \$143.0 million. These properties contributed 2,824 boepd to 2004 production.
- Realized a \$16.6 million gain on disposition of several properties in December 2004.
- Sold a 16 percent interest in WHITESANDS Insitu Ltd. and recorded a pre-tax gain of \$4.7 million in the second quarter of 2005.
- Canadian production increased successively in each quarter during 2005 averaging 3,127 boepd in the fourth quarter and exiting the year at approximately 4,000 boepd. These increases were primarily a result of development drilling and facilities expansion at Jumpbush.
- Commodity prices climbed throughout 2005 and reached their peak in the second half of 2005, resulting in higher netbacks and net income.
- As \$50.5 million, or approximately 50 percent, of the outstanding face value of subordinated notes were repurchased throughout 2005 the related interest expense decreased proportionately resulting in improved profitability.
- Significant increases in proved reserves at the end of both 2004 and 2005 lowered depletion and resulted in higher profitability in 2005.

Liquidity and Capital Resources

At December 31, 2005 net debt totaled \$60.8 million, including \$49.0 million book value of outstanding subordinated notes. The subordinated notes are not callable and mature on July 31, 2006. Earlier in 2005, the Company negotiated a new secured bank credit facility, consisting of two tranches, with a combined total available borrowing base of \$35 million, none of which was drawn in 2005. In February 2006, the Company issued an additional 2,597,403 common shares for gross proceeds of \$33.4 million (\$30.6 million net of costs) in connection with a public offering and secondary listing on the Oslo stock exchange.

The Company had the following contractual obligations as at December 31, 2005:

Type of Obligation (\$000s)	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Subordinated notes (face value)	49,924	49,924	-	-	-
Colombian exploration commitments (US\$)	6,200	6,200	-	-	-
WHITESANDS compressor lease (US\$)	2,054	239	822	822	171
Office operating leases	962	661	301	-	-

The Company has first-phase work commitments remaining on its five new exploration contracts in Colombia totaling an additional US\$5.3 million which are to be incurred before October 2006 and include reprocessing 2-D and 3-D seismic, shooting additional 3-D seismic, and drilling one well on the Joropo Block in the Llanos Basin. Upon completion of the first-phase commitments the Company can elect to return individual blocks to the National Hydrocarbon Agency ("ANH") or proceed to a second-phase by drilling one well per block.

The Company's remaining work commitments on the three new technical evaluation areas ("TEA") in Colombia are expected to total US\$0.9 million through October 2006 and include reprocessing and evaluating existing 2-D seismic, and performing regional studies including the feasibility of the Company's patented THAI™ heavy oil recovery process. Upon expiry of the contracts, the Company has the option to negotiate an exploration block within the TEA. During the contract period, the Company also has a right of first refusal over any exploration blocks proposed by third parties within the TEA.

The Company is committed to spend US\$2.1 million over five years for air compression rental at the WHITESANDS pilot project. The term is expected to commence in the first half of 2006.

The Canadian Business Unit's capital plan is focused on development of Petrobank's core property at Jumpbush, development of partially matured areas such as Red Willow, exploration of prospects such as Macklin and Innes, and leveraging the Company's significant undeveloped land base into new resource opportunities. Success will enhance the Company's cash position and borrowing capacity under its secured credit facility. In addition to conventional opportunities, the Canadian Business Unit has coal bed methane ("CBM") potential at both its Jumpbush and Princeton properties. The Princeton project requires more up front capital than Jumpbush because of its location and the nature of the reservoir. The CBM projects will be more difficult to finance with conventional debt until they have been proven commercial.

The Latin American Business Unit plans to drill up to six wells at Orito, up to 10 at Neiva, and one on the Joropo exploration block. To address the shortage of rig availability in Colombia, the Company executed a Letter of Intent that provides an option to secure a rig for a minimum 16-month term commencing in mid-2006. Depending on success, an expanded Colombian capital budget could be financed with the proceeds from the planned initial public offering ("IPO") of the Company's subsidiary, Petrominerales Colombia Ltd. ("Petrominerales"). The proposed IPO involves listing Petrominerales on the Toronto and Oslo stock exchanges and the Company expects to sell a minority portion of its shareholdings in Petrominerales, providing increased financial flexibility for Petrobank.

The Heavy Oil Business Unit acquired a total of 15 additional sections of oil sands leases in October 2005 and February 2006, and the remaining focus for 2006 is to complete construction of the WHITESANDS pilot project that will test the use of the Company's patented THAI™ technology. Construction of the surface facilities commenced in mid-2005 and is substantially complete. The project is comprised of three well pairs that are expected to be on production by the end of 2006. Total estimated costs to construct the project are approximately \$40 million with approximately \$10 million remaining to be spent in 2006. The minority shareholder of WHITESANDS Insitu Ltd. is expected to fund its 16 percent share of construction costs

in excess of \$34 million and other additional costs associated with WHITESANDS activities. With success, a commercial WHITESANDS project would require a combined investment of approximately \$500 million.

The Company's Canadian credit facility is secured by all of the Company's assets in Canada and is due on demand by the lender. The lender periodically, and at least annually, assesses the amount of the borrowing base available, which determines how much the Company can draw under each of the two tranches. The borrowing base is determined according to a number of factors, primarily the lender's commodity price outlook, the quantity of the Company's Canadian proved producing reserves and future production profile. The current borrowing base is expected to be revised upwards by the end of April 2006.

The Company does not have significant recurring working capital requirements, and typically settles its vendor liabilities following collection of oil and gas revenues. Working capital levels fluctuate primarily based on capital expenditure activity and oil and gas revenues.

Possible sources of funds available to Petrobank include the following:

- Additional government incentive programs, including the Government of Alberta's Innovation Energy Technologies Program, may be available to fund a portion of the WHITESANDS THAI™ pilot project costs and potentially costs associated with testing the Company's related CAPRI™ technology.
- Petrobank may issue common shares in Canada or Norway, with or without flow-through tax benefits. In Canada, flow-through shares allow the Company to pass the deductibility of certain oil and natural gas expenditures through to subscribers. Typically, these shares attract a premium to existing market prices, but the amount that can be raised is limited to exploration expenditures incurred in Canada within a 12-24 month period following the issue.
- Petrobank may sell producing or non-producing assets to raise funds in the short term. Incremental cash resources generated as a result would be reduced by any resulting decreases in future cash flows and the borrowing base under Petrobank's secured credit facility.
- Management is pursuing an additional credit facility secured by the Company's Colombian assets. Interest expense on such a facility would typically be 200-300 basis points per annum higher than that under the Canadian credit facility.
- Petrobank has the ability to issue incremental subordinated debt. This could be an incremental offer of the subordinated notes currently outstanding, or other similar debt.
- Petrobank is considering the issuance of longer-term senior secured debt to refinance the existing \$49.9 million face value of subordinated notes maturing on July 31, 2006. If the Company does not refinance the subordinated notes with new debt, an incremental equity issue would likely be required.
- An alternative financing vehicle is pre-export financing or a pre-sale of a portion of future oil production in Colombia. Petrobank's Orito and Neiva contracts specifically permit the export of oil and there is no requirement for such proceeds to be remitted to Colombia.
- Following the planned IPO of the Company's subsidiary, Petrominerales, Petrobank has the option to sell all or a portion of its remaining shareholdings in Petrominerales in the secondary market to generate funds required for other projects. In addition, Petrominerales could raise additional funds through the issuance of additional common shares.

Petrobank does not anticipate Colombian cash flows to exceed capital expenditures over the next 12-24 months. There are no legal restrictions on repatriating funds to Canada once excess net cash flows are achieved.

Management's plan for the remainder of 2006 is to deploy the Company's resources and to execute on the Company's inventory of opportunities during their capital-intensive phases.

Risks and Uncertainties

Petrobank is exposed to a variety of risks, including but not limited to competitive, operational, political, environmental, and financial.

The oil and gas industry is highly competitive, particularly in regard to exploration for, and development of new sources of crude oil and natural gas reserves. The competition for land and resources in western Canada is especially intense. Competitors include companies much larger than Petrobank, with greater access to financial resources. The Company's future success is driven, in large part, by its ability to find and exploit new oil and natural gas reserves at reasonable costs and reinvestment ratios. The process of evaluating prospects and estimating oil and natural gas reserves is complex and subject to significant uncertainty. Actual operating results, including production performance, will vary from those estimated, possibly materially. The Company manages these risks by maintaining a focused asset base with high working interests and by hiring qualified professionals, including independent reserve engineers, with appropriate industry experience.

Petrobank is exposed to a number of operational risks inherent in the industry including accidents, well blowouts, uncontrolled flows and environmental risks. Operational risks are managed using prudent field operating procedures. The Company has a detailed emergency response plan to deal with potential incidents and maintains a comprehensive insurance program to reduce the risk of significant economic loss; however, not all risks can be eliminated. Losses resulting from the occurrence of these risks could have a material adverse impact on the Company's operations.

Petrobank currently has operations in Canada and Colombia and is evaluating additional projects internationally. To help mitigate the risks associated with operating in foreign jurisdictions, the Company seeks to operate in regions where the petroleum industry is a key component of the economy. Petrobank believes that management's experience operating both domestically and internationally helps reduce these risks. Some countries in which the Company may operate may be considered politically and economically unstable. In Colombia, the government has a long history of democracy and an established legal framework that, in Petrobank's opinion, minimize political risks.

Colombia has a publicized history of security problems associated with certain narco-terrorist groups. The Company and its personnel are subject to these risks, but through effective security and social programs, Petrobank believes these risks can be effectively managed. It is difficult to obtain insurance coverage to protect against terrorist incidents and as a result the Company's insurance program excludes this coverage. Consequently, incidents like this in the future could have a material adverse impact on the Company's operations.

The Company's WHITESANDS pilot project entails risks incremental to those of conventional oil and gas operations. Although other operators have utilized the individual processes involved in the pilot in the past, the pilot project's configuration of wells and processes is a new combination, and thus Petrobank is subject to unknown operational risks. Other risks associated with the pilot include: the THAI™ technology will prove unsuccessful or commercially unviable; the cost of the pilot will exceed management's initial estimates; and, unknown future regulatory or commodity market factors will make the technology uneconomic. However, management believes that the technology, if successful, would be a step change in heavy oil recovery technology and would address many of the existing risks and economic challenges currently facing the oil sands industry in Canada as well as international heavy oil projects.

The Company is subject to extensive governmental and environmental regulations in its operating jurisdictions. Changes to these regulations, including the implementation of the Kyoto Protocol, could increase the costs of conducting business in these jurisdictions. Environmental risks inherent in the oil and gas industry are subject to increasingly stringent legislation and regulation. The Company operates in accordance with all relevant environmental legislation and strives to minimize the environmental impact of its operations by providing for safety and environmental issues in all of its business plans.

Petrobank is exposed to normal financial risks inherent within the oil and gas industry, including commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company conducts its operations in a manner intended to minimize exposure to these risks as described in Note 14 to the Consolidated Financial Statements.

Commodity prices are the Company's most significant financial risk. Crude oil prices are influenced by global supply and demand, OPEC policy, and worldwide political events. Natural gas prices in Canada are influenced primarily by North American supply and demand and to a lesser extent by local market conditions. Weather events and conditions also play a major role in the supply and demand both commodities. Fluctuations in commodity prices not only affect the Company's cash flows, but may also result in changes to the borrowing capacity under Petrobank's credit facility as assessed by the Company's lender. Management believes it is neither appropriate nor possible to eliminate 100 percent of the Company's exposure to fluctuations in commodity prices. The Company monitors market conditions and selectively utilizes derivative instruments to reduce exposure to commodity price movements.

To the extent revenues and expenditures denominated in or strongly linked to the U.S. dollar are not equivalent, the Company is exposed to exchange rate risk. Revenues in Canada are largely determined by a U.S. dollar reference price. In Colombia, the Company is exposed to the extent U.S. dollar revenues do not equal U.S. dollar expenditures. The Company is not currently using exchange rate derivatives to manage exchange rate risks.

Petrobank is exposed to fluctuations in short-term interest rates on amounts drawn under its floating-rate bank facility. The Company has not hedged these rates given the need to remain flexible in borrowing and repaying outstanding balances. The Company's outstanding debt during 2005 was comprised solely of subordinated notes which pay a fixed nine percent interest rate which minimizes Petrobank's exposure to interest rate risk.

In addition to the foregoing risks, readers are directed to the section entitled, "Risk Factors" in the Company's AIF.

Sensitivities

The Company's earnings and cash flow are sensitive to changes in crude oil and natural gas prices, and exchange rates.

The following factors demonstrate the expected impact on cash flow from operations:

		(\$ millions)
Change of:		
Crude oil	US\$1.00/bbl WTI reference price	\$ 0.7
	100 bbls per day in Canadian production @ US\$55/bbl WTI	\$ 1.2
	100 bbls per day in Colombian production @ US\$55/bbl WTI	\$ 1.5
Natural gas	US\$0.50/mmbtu NYMEX reference price	\$ 2.9
	1.0 mmcf per day production @ US\$7.00/mmbtu NYMEX	\$ 1.6
Currency	\$0.01 in Cdn\$/US\$ exchange rate	\$ 0.8

Transactions with Related Parties

In 2004, the Company paid a \$0.2 million commitment fee to secure a \$10 million credit facility from a company controlled by a former director of Petrobank. No amount was drawn on this facility which expired on December 30, 2004.

Critical Accounting Policies and Estimates

The Company's financial statements are prepared in accordance with Canadian GAAP, which require management to make judgments, estimates and assumptions which may have a significant impact on the financial statements. A summary of the Company's significant accounting policies can be found in Note 2 to the Consolidated Financial Statements. The following is a discussion of those accounting policies and estimates that are considered critical in the determination of the Company's financial results.

Capital Assets – Full Cost Accounting

The Company follows the full cost method of accounting as described in Note 2 to the Consolidated Financial Statements. Alternatively, the Company could follow the successful efforts method of accounting whereby all costs related to non-productive wells are expensed in the period in which they are incurred.

Under the full cost method of accounting, capitalized costs are subject to a country-by-country cost centre impairment test. Under the successful efforts method of accounting, the costs aggregated on a property-by-property basis and the carrying value of each property is subject to an impairment test. These policies may result in a different carrying value for capital assets and a different net income. The Company has elected to follow the full cost method and it is the method most commonly followed.

Under full cost accounting, a limit is placed on the carrying value of the net capitalized costs in each cost centre in order to test impairment. Impairment exists when the carrying value of developed properties of a cost centre exceeds the estimated undiscounted future net cash flows associated with the cost centre's proved reserves. Costs relating to undeveloped properties are subject to individual impairment assessments until it can be determined whether or not proved reserves exist. If impairment is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the cost centre's proved plus probable reserves are charged to income.

Reserve Estimates

Reserve estimates can have a significant impact on net income and the carrying value of capital assets. The process of estimating reserves requires significant judgment based on available geological, geophysical, engineering, and economic data, projected rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to interpretation and uncertainty. Reserve estimates impact net income through depletion expense and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income and can impact the carrying amount of capital assets.

Petrobank's lender also uses reserve estimates to assess the borrowing base under the secured bank credit facility. Changes to the reserve estimates can result in borrowing base increases or decreases, which may impact the Company's financial position.

Asset Retirement Obligations

The Company recognizes the estimated fair value of future retirement obligations associated with capital assets as a liability. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership in tangible long-lived assets such as wells and facilities and the estimated timing of the costs to be incurred in future periods. Actual payments to settle the obligations may differ from estimated amounts.

Changes in Accounting and Regulatory Policies

Financial Instruments

Effective January 1, 2005 the Company retroactively adopted the revised recommendation of the CICA Section 3860, "Financial Instruments – Disclosure and Presentation", on the classification of obligations that must or could be settled with an entity's own equity instruments. The revised recommendation requires securities such as Petrobank's subordinated notes to be reclassified from equity to liabilities on the balance sheet. For the year ended December 31, 2004 there was no impact on earnings per share but interest expense on the subordinated notes of \$11.5 million and the related future income tax recovery of \$3.8 million were deducted when calculating net income rather than the net income attributable to common shareholders as previously reported.

Certification of Disclosures in Annual and Interim Filings

Commencing in 2005, the Company is required to issue a "Modified Certification of Annual Filings during Transition Period" ("Modified Certification") in accordance with Multilateral Instrument 52-109, "Certification of Disclosures in Issuers' Annual and Interim Filings". The Modified Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures and as such, have designed such procedures and evaluated their effectiveness as of the end of the period covered by the annual filings. Management believes the disclosure controls and procedures provides a reasonable level of assurance that information required to be disclosed by the Company in its annual filings, is recorded, processed, summarized and reported within the time periods specified and the controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to Petrobank's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Outlook

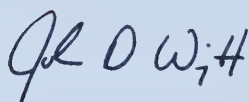
In addition to the plans discussed herein, please see the President's Letter and the Operations Review for a discussion of the Company's future business prospects.

MANAGEMENT'S REPORT

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the consolidated financial statements and other financial and operating data contained elsewhere in this report. The accompanying consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgement, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying consolidated financial statements have been prepared using policies and procedures established by management and fairly reflect the Company's financial position, results of operations and changes in financial position, within Canadian generally accepted accounting principles. Management has established and maintains a system of internal controls that is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

The consolidated financial statements have been examined by the Company's external auditors, Deloitte & Touche LLP. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported financial results and the financial condition of the Company.

The Audit Committee of the Board of Directors has reviewed in detail the consolidated financial statements with management and the external auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.



John D. Wright
President & Chief Executive Officer
Calgary, Canada
March 10, 2006



Chris J. Bloomer
Vice-President Heavy Oil & Chief Financial Officer

AUDITORS' REPORT

TO THE SHAREHOLDERS OF PETROBANK ENERGY AND RESOURCES LTD.:

We have audited the consolidated balance sheets of PETROBANK ENERGY AND RESOURCES LTD. as at December 31, 2005 and 2004 and the consolidated statements of operations and retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Deloitte & Touche LLP
Chartered Accountants
Calgary, Canada
March 10, 2006

CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian dollars)

As at December 31,	2005	2004
		(Restated – Note 3)
Assets		
Current assets		
Cash and cash equivalents	\$ 25,343	\$ 75,509
Accounts receivable and other current assets	21,727	13,063
	47,070	88,572
Capital assets (Note 4)	213,912	116,820
	\$ 260,982	\$ 205,392
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 58,834	\$ 27,893
Subordinated notes (Note 9)	49,044	-
	107,878	27,893
Obligations under gas sale and transportation contracts (Note 7)	5,650	6,477
Asset retirement obligations (Note 8)	7,931	2,870
Future income tax liability (Note 11)	10,358	15,492
Subordinated notes (Note 9)	-	95,862
	131,817	148,594
Non-controlling interest (Note 5)	8,406	-
Shareholders' equity		
Common shares (Note 10)	123,262	73,157
Contributed surplus (Note 10)	1,573	525
Deficit	(4,076)	(16,884)
	120,759	56,798
	\$ 260,982	\$ 205,392

Subsequent events (Notes 10 and 12)

Commitments and contingencies (Note 16)

See accompanying notes to these consolidated financial statements.

Signed on behalf of the Board:



James D. Tocher
Chairman



Kenneth R. McKinnon
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

(Thousands of Canadian dollars, except per share amounts)

Years ended December 31,	2005	2004
		(Restated – Note 3)
Revenues		
Oil and natural gas	\$ 65,081	\$ 73,377
Royalties	(10,857)	(13,372)
	54,224	60,005
Expenses		
Production	8,912	15,291
Transportation	866	1,526
General and administrative	7,648	7,134
Stock-based compensation	1,168	338
Interest on bank debt	-	1,246
Interest on subordinated notes	8,429	11,471
Depletion, depreciation and accretion	16,382	33,367
	43,405	70,373
Income (loss) before other items and taxes	10,819	(10,368)
Gain (Notes 4 and 5)	4,744	16,632
Loss on repurchase of subordinated notes (Note 9)	(968)	-
Other income (expense)	844	(1,277)
Net income before taxes	15,439	4,987
Capital taxes	(2,024)	(1,470)
Future income taxes (Note 11)	(607)	(2,684)
Net income	12,808	833
Deficit, beginning of year	(16,884)	(17,717)
Deficit, end of year	\$ (4,076)	\$ (16,884)
Earnings per share (Note 10)		
Basic	\$ 0.22	\$ 0.02
Diluted	\$ 0.21	\$ 0.02

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(Thousands of Canadian dollars)

Years ended December 31,	2005	2004
		(Restated – Note 3)
Operating Activities		
Net income	\$ 12,808	\$ 833
Depletion, depreciation and accretion	16,382	33,367
Non-cash stock compensation (Note 10)	1,168	338
Future income taxes (Note 11)	607	2,684
Amortization of discount on subordinated notes (Note 9)	1,963	2,432
Gain (Notes 4 and 5)	(4,744)	(16,632)
Loss on repurchase of subordinated notes (Note 9)	968	-
Loss recorded on disposition of sales contract (Note 4)	-	375
Cash flow from operations	29,152	23,397
Asset retirement obligations settled	(262)	(311)
Changes in other non-cash working capital (Note 15)	(1,003)	8,568
	27,887	31,654
Financing Activities		
Issuance of common shares (Note 10)	48,880	802
Repurchase / redemption of subordinated notes (Note 9)	(49,749)	-
Issuance of shares by subsidiary (Note 5)	12,651	-
Repayment of bank debt	-	(30,102)
Repayment of debenture	-	(14,014)
Amortization of obligations under gas sale and transportation contracts (Note 7)	(827)	(810)
Changes in other non-cash working capital (Note 15)	-	25
	10,955	(44,099)
Investing Activities		
Expenditures on capital assets	(118,152)	(47,901)
Proceeds on disposition of capital assets (Note 4)	-	143,027
Changes in other non-cash working capital (Note 15)	29,144	(7,172)
	(89,008)	87,954
Net change in cash position	(50,166)	75,509
Cash and cash equivalents, beginning of year	75,509	-
Cash and cash equivalents, end of year	\$ 25,343	\$ 75,509

See accompanying notes to these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2005 and 2004

(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts or as otherwise noted)

Note 1 – Description of Business

Petrobank Energy and Resources Ltd. (the “Company” or “Petrobank”), is a public company listed on the Toronto and Oslo Stock Exchanges and incorporated under the Business Corporations Act (Alberta). Petrobank is engaged in the exploration for and development and production of oil and natural gas in the country of Colombia and in the Western Canadian Sedimentary Basin. Petrobank operates projects through three business units. The Canadian Business Unit combines conventional oil and gas operations with coal bed methane opportunities. The Latin American Business Unit has exploration contracts covering 2.5 million acres and production from two blocks in Colombia. The Heavy Oil Business Unit holds oil sands leases near Conklin, Alberta and is implementing the WHITESANDS pilot project to field-demonstrate Petrobank’s patented THAI™ heavy oil recovery process.

Note 2 – Significant Accounting Policies

These consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and include the accounts of the Company and its subsidiaries. Certain prior years’ amounts have been reclassified to conform with current presentation.

Measurement Uncertainty

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated balance sheets as well as the reported amounts of revenues, expenses, and cash flow during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the consolidated financial statements. Actual results could differ materially from estimated amounts.

Amounts recorded for depreciation, depletion and accretion costs and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves that are subject to measurement uncertainty. Changes in these estimates could materially impact the consolidated financial statements of future periods.

Capital Assets – Oil and Gas

All costs related to the acquisition of oil and natural gas properties are capitalized. Such costs include land and lease acquisition costs, annual charges on non-producing properties, geological and geophysical costs, and costs of drilling and equipping productive and non-productive wells.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of more than 20 percent.

Capitalized costs are accumulated in cost centres on a country-by-country basis and are depreciated and depleted using the unit-of-production method based upon estimated proved reserves before royalties as determined by independent engineers. Costs subject to depletion include estimated costs to develop proved reserves and exclude estimated salvage value. Reserve and production volumes of oil and natural gas are converted to common units on the equivalency basis of 6 mcf to 1 bbl, reflecting the approximate relative energy content. Costs relating to undeveloped properties may be excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. Depreciation of office equipment is provided at 30 percent using the declining balance method.

A limit is placed on the carrying value of the net capitalized costs in each cost centre in order to test impairment. Impairment exists when the carrying value of a cost centre exceeds the estimated undiscounted future net cash flows associated with the cost centre’s proved reserves. If impairment is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the cost centre’s proved plus probable reserves are charged to income. Reserves are determined pursuant to National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities”.

The Company does not capitalize general and administrative or interest costs.

Asset Retirement Obligations

The Company recognizes the estimated fair value of future retirement obligations associated with capital assets as a liability. The fair value is capitalized and amortized over the same period as the underlying asset. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is applied prospectively. The change in net present value of the future retirement obligations as time passes is expensed as accretion. The asset retirement cost, equal to the fair value of the asset retirement obligations, is capitalized as part of the cost of the related long-lived asset and amortized using the unit-of production method. Actual retirement obligations settled during the period reduce the accumulated obligations.

Non-Controlling Interest

Non-controlling interest represents a 16 percent interest in the Company’s previously wholly-owned subsidiary WHITESANDS Insitu Ltd. (“WHITESANDS”) which was sold to a third party. Non-controlling interest on the consolidated balance sheet represents the reduction of the Company’s interest as a result of the sale. There are negligible revenues and expenses currently being incurred in WHITESANDS, with the majority of activity being capitalized. In the future as earnings or losses are realized the Company’s net income will be adjusted to reflect the portion attributable to the non-controlling interest.

Derivative Financial Instruments

The Company may utilize derivative financial instruments in its management of exposures to fluctuations in crude oil and natural gas prices, foreign currency exchange rates and interest rates. The Company does not enter into derivative financial instruments for trading or speculative purposes. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Gains and losses on contracts that constitute effective hedges are deferred and recognized in income when the related transactions occur.

Joint Operations

The majority of the Company's oil and natural gas operations are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Revenue Recognition

Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized when title passes to the customer.

Foreign Currency Translation

The Company translates foreign currency denominated monetary assets and liabilities of its integrated foreign subsidiaries at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities are translated at historical exchange rates. Revenues and expenses are translated at estimated transaction date exchange rates except depletion and depreciation expense, which is translated at the same historical exchange rates as the related assets. Exchange gains or losses are included in the determination of net income as other income (expense).

Earnings Per Share

The Company computes diluted earnings per share using the treasury stock method. This method assumes that the proceeds on exercise of in-the-money stock options and share purchase warrants are used to repurchase the Company's common shares at the average market price during the relevant period.

Stock-Based Compensation

The Company accounts for stock-based compensation using the fair-value method of accounting for stock options and deferred common shares (collectively referred to as "Rights") granted to employees, officers and directors. Stock-based compensation expense is recorded and reflected as stock-based compensation expense for all Rights granted after January 1, 2003, with a corresponding amount reflected in contributed surplus. Stock-based compensation expense is calculated as the estimated fair value of the related Rights at the time of the grant, amortized over the expected life. When Rights are exercised, the associated amounts previously recorded as contributed surplus are reclassified to common share capital.

Income Taxes

The Company accounts for income taxes using the liability method. Under this method, the Company records a future income tax asset or liability to reflect any difference between the accounting and tax bases of assets and liabilities. Future income tax assets are only recognized to the extent it is more likely than not that sufficient future taxable income will be available to allow the future income tax asset to be realized.

Government Assistance

The Company records the benefit of government assistance as a reduction in the related capital expenditures as they are incurred.

Investment Tax Credits

Investment tax credits arise as a result of incurring qualified scientific research and development expenditures ("SR&ED"), and are recorded as a reduction of the related expenditure or carrying value when there is reasonable assurance of collection.

Flow-Through Common Shares

The Company has historically financed a portion of its exploration activities in Canada through the issuance of flow-through shares. Under the terms of these shares, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded in the period in which the related tax attributes are effectively renounced.

Cash and Cash Equivalents

Cash and cash equivalents include securities with a maturity of three months or less when purchased.

Note 3 – Changes in Accounting Policies

Financial Instruments

Effective January 1, 2005 the Company retroactively adopted the revised recommendation of the CICA Section 3860, “Financial Instruments – Disclosure and Presentation”, on the classification of obligations that must or could be settled with an entity’s own equity instruments. The revised recommendation requires securities such as Petrobank’s subordinated notes to be reclassified from equity to liabilities on the balance sheet. For the year ended December 31, 2004, there was no impact on earnings per share but interest expense on the subordinated notes of \$11.5 million and the related future income tax recovery of \$3.8 million were deducted when calculating net income rather than the net income attributable to common shareholders as previously reported.

Note 4 – Capital Assets

December 31, 2005	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	\$ 157,764	\$ 80,220	\$ 77,544
Heavy Oil	35,445	-	35,445
Colombia	139,894	39,707	100,187
Corporate and other	5,086	4,350	736
	\$ 338,189	\$ 124,277	\$ 213,912

December 31, 2004	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	\$ 109,578	\$ 71,498	\$ 38,080
Heavy Oil	9,269	-	9,269
Colombia	101,305	32,774	68,531
Corporate and other	4,830	3,890	940
	\$ 224,982	\$ 108,162	\$ 116,820

At December 31, 2005, oil and natural gas properties included \$44.0 million (2004 – \$11.9 million) relating to unproved properties in Canada, which are primarily costs related to the Company’s WHITESANDS pilot project, and \$7.9 million (2004 – \$3.9 million) related to international unproved properties, primarily in Colombia, that have been excluded from the depletion calculation.

An impairment test calculation was performed for each of the Canadian and Colombian cost centres at December 31, 2005 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amounts. In determining the undiscounted future net cash flows for each cost centre, the Company utilized benchmark pricing forecasts from two reserve evaluators, one for Canadian assets and one for Colombian assets. The benchmark prices used in the impairment tests at December 31, 2005 are outlined in the following table:

Year	Canada		Colombia
	WTI Crude Oil ⁽¹⁾ – US\$/bbl	AECO Natural Gas ⁽¹⁾ – Cdn\$/mcf	WTI Crude Oil – US\$/bbl
2006	\$ 60.81	\$ 11.58	\$ 58.00
2007	61.61	10.84	56.38
2008	54.60	8.95	52.53
2009	50.19	7.87	51.69
2010	47.76	7.57	52.72
Thereafter inflation % change	1.5%	1.7% until 2016, 1.5% thereafter	2%

(1) Actual prices used in the impairment tests were adjusted for price differentials specific to the Company’s operations. The US\$/Cdn\$ exchange rate used for all years was 0.85.

Dispositions

Petrobank did not dispose of any properties in 2005 after completing several property dispositions during 2004 for total proceeds of \$143.0 million. The most significant disposition occurred on December 16, 2004 when the Company disposed of certain properties for proceeds net of purchase price adjustments of \$96.1 million. The properties disposed of included Nevis, Rainbow, and Shekilie in Alberta, and Lashburn, Eyehill, and Red Jacket in Saskatchewan. The Company recorded a pre-tax gain of \$16.6 million on this transaction.

Petrobank disposed of its Wapella property on January 28, 2004 for net proceeds of \$35.5 million. As part of this sale, the purchaser assumed the Company's fixed oil sales price contract on 300 barrels of oil per day at a WTI price of \$27.68 per barrel. At the time of the sale, this contract had a negative fair value of \$0.4 million, which was recorded as other expense.

Note 5 – Gain

On April 12, 2005 the Company sold a 16 percent interest in its previously wholly-owned subsidiary, WHITESANDS for proceeds of \$14.0 million (\$12.7 million net of issuance costs). The reduction in the Company's interest in WHITESANDS resulted in a pre-tax gain of \$4.7 million.

Under the financing agreement, on an annual basis, the investor may request a third-party valuation of WHITESANDS and may require the Company to repurchase the investor's interest in WHITESANDS at fair market value. The Company has the option to fund this repurchase with cash or through the exchange of Petrobank common shares, valued at 95 percent of the 10-day weighted average trading price prior to the date of exchange.

Note 6 – Bank Debt

The Company had no bank debt outstanding at December 31, 2005 under its \$20 million secured credit facility. In addition, a further \$15 million secured development loan facility is available to fund the acquisition and/or development of producing or proved non-producing petroleum and natural gas reserves in Canada. The first facility is a revolving demand loan under which the Company can borrow at bank prime plus 0.25 percent or Bankers' Acceptance fee rates plus 1.25 percent. The development loan facility is a non-revolving demand loan under which the Company can borrow at bank prime plus 0.5 percent. Advances under the facilities are secured by a \$75 million debenture with a floating charge over all Canadian assets of the Company as well as a general assignment of the Company's accounts receivable, a negative pledge to provide fixed charges on major producing petroleum properties in Canada and an assignment of material contracts.

The Company also maintains a US\$0.9 million unsecured credit facility in Colombia primarily used for letters of credit issued in connection with the Company's exploration licenses in Colombia.

Note 7 – Obligations under Gas Sale and Transportation Contracts

The Company assumed certain physical natural gas sales and transportation obligations upon the acquisition of Barrington Petroleum Ltd. in 2001. The Company recorded a liability for these obligations at that time, which is being amortized to oil and natural gas revenues over the term of the related contracts (Note 14).

Note 8 - Asset Retirement Obligations

The total future asset retirement obligations were estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods.

Changes to asset retirement obligations were as follows:

	2005	2004
Asset retirement obligations, beginning of year	\$ 2,870	\$ 9,602
Obligations incurred	4,674	981
Obligations settled	(262)	(311)
Obligations disposed	-	(4,492)
Accretion expense	267	756
Change in estimated future cash flows and other	382	(3,666)
Asset retirement obligations, end of year	\$ 7,931	\$ 2,870

The obligations have been calculated using an inflation rate of two percent and discounted using a credit-adjusted risk free rate of eight percent per annum. Most of these obligations are not expected to be paid for several years extending up to 40 years in the future, and are expected to be funded from general Company resources at the time of settlement. The total undiscounted amount of estimated cash flows required to settle the obligations at December 31, 2005 is \$32.1 million (2004 – \$15.1 million).

Note 9 – Subordinated Notes

Petrobank's subordinated notes are unsecured and subordinate to the Company's existing credit facilities and any other senior debt that may be outstanding from time to time. Interest on the notes is payable quarterly at a rate of nine percent per annum and the notes mature on July 31, 2006. The notes may be repaid at their face value prior to their maturity date and the Company has the option of issuing common shares, at market price, to settle quarterly interest payments as well as the principal amount. The notes were recorded at fair value on issuance and the discount to face value is being amortized to interest on subordinated notes over the term of the notes, creating an effective interest rate of 12 percent.

The Company repurchased a total of \$50.5 million face value of outstanding subordinated notes throughout 2005 for \$49.7 million, and recorded a pre-tax loss totaling \$1.0 million as a result of the transactions.

	Carrying Amount	Principal Amount
Balance at December 31, 2003	\$ 93,430	\$ 100,438
Amortization of discount	2,432	-
Balance at December 31, 2004	\$ 95,862	\$ 100,438
Amortization of discount	1,963	-
Repurchases	(48,781)	(50,514)
Balance at December 31, 2005	\$ 49,044	\$ 49,924

Note 10 – Share Capital

Authorized

Unlimited number of common shares

Unlimited number of preferred shares, issuable in series

Common Shares

	Number	Amount
Balance at December 31, 2003	54,502,646	\$ 72,355
Exercise of stock options	453,750	802
Balance at December 31, 2004	54,956,396	\$ 73,157
Exercise of stock options	795,725	1,735
Exercise of warrants	467,600	1,870
April 12, 2005 private placement	3,000,000	9,750
October 20, 2005 private placement	4,000,000	38,600
Share issue costs	-	(3,075)
Tax effect of share issue costs	-	1,105
Transfer from contributed surplus related to stock options exercised	-	120
Balance at December 31, 2005	63,219,721	\$ 123,262

On February 7, 2006 the Company issued 2,597,403 common shares for gross proceeds of \$33.4 million (\$30.6 million net of costs) in connection with a public offering and secondary listing on the Oslo stock exchange.

Share Purchase Warrants

As at December 31, 2005, the Company had 952,700 (2004 - 1,420,300) share purchase warrants outstanding which allow the holders to purchase an equivalent number of common shares at \$4.00 per share on or before May 6, 2006.

Stock Options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees, consultants and underwriters. Subject to shareholder approval, the Company has amended the plan to allow for the issuance of up to 10 percent of the outstanding common shares of the Company, less shares reserved under other Company stock-based compensation plans such as the deferred share compensation plan. The exercise price of each option is no less than the market price of the Company's stock on the date of the grant. Stock option terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of four years from the date of grant and expire five years after the date of grant. The following is a continuity of stock options outstanding.

	2005		2004	
	Stock Options	Weighted-Average Exercise Price	Stock Options	Weighted-Average Exercise Price
Opening	3,381,751	\$ 2.47	3,676,501	\$ 2.42
Granted	1,809,500	5.48	1,018,750	2.30
Exercised	(795,725)	2.18	(453,750)	1.77
Cancelled	(257,000)	2.64	(859,750)	2.43
Closing	4,138,526	\$ 3.83	3,381,751	\$ 2.47

The following summarizes information about stock options outstanding as at December 31, 2005:

Range of Exercise Prices \$	Number Outstanding	Weighted-Average Remaining Contractual Life (Years)	Weighted- Average Exercise Price	Number Exercisable	Weighted- Average Exercise Price
1.50 – 2.49	1,188,451	2.8	\$ 2.08	522,576	\$ 1.94
2.50 – 3.99	1,405,575	2.7	3.13	555,200	3.07
4.00 – 6.99	1,051,500	4.3	4.49	-	-
7.00 – 10.70	493,000	4.8	8.64	1,000	8.75
	4,138,526	3.4	\$ 3.83	1,078,776	\$ 2.53

Deferred Share Compensation Plan

The Company has established a deferred share compensation plan whereby the Company may grant deferred common shares to its directors, officers and employees. The Company's shareholders have approved the issuance of up to 0.5 million deferred common shares under this plan. Issuance of the common shares requires payment in the amount of \$0.05 for each common share and participants are not entitled to issuance until a period of three years has passed since the date of grant, expiring 10 years following the date of grant. There were 140,000 deferred common shares outstanding under this plan at December 31, 2005.

Stock-Based Compensation

The Company uses the fair value-based method of accounting for its stock-based compensation plans whereby the fair value of stock options and deferred common shares (collectively referred to as "Rights") granted after January 1, 2003 is recognized as stock-based compensation expense and as contributed surplus. Stock-based compensation cost for the year ended December 31, 2005 totaled \$1.2 million (2004 – \$0.3 million).

The fair value of Rights granted has been estimated on their respective grant dates using the Black-Scholes option-pricing model using the following assumptions:

Years ended December 31,	2005	2004
Risk free interest rate	4.25%-4.5%	4.0%-4.5%
Dividend rate	0%	0%
Expected life – options (years)	4	4
Expected life – deferred common shares (years)	8	N/A
Expected volatility	30%-50%	30%

The average value per Right granted during the year ended December 31, 2005 was \$2.52 (2004 – \$0.69) as at the date of grant.

Earnings Per Share

Basic and diluted earnings per share have been calculated based on net income, divided by the weighted average number of common shares outstanding for the year ended December 31, 2005 of 58,526,249 (2004 – 54,690,337). The diluted calculations for the year ended December 31, 2005 include 1,074,494 (2004 – nil) additional shares for the potential impact of share purchase warrants, stock options and deferred common shares.

Note 11 – Income Taxes

The provision for income taxes differs from the amount that would have been expected by applying statutory corporate income tax rates to net income before taxes. The principal reasons for this difference are as follows:

	2005	2004
Net income before taxes	\$ 15,439	\$ 4,987
Statutory income tax rate	37.90%	39.13%
Expected tax expense	\$ 5,851	\$ 1,951
Increase (decrease) in income tax provision resulting from:		
Non-deductible portion of Crown charges	228	1,460
Resource allowance	(848)	(1,258)
Future tax asset recognized	(1,654)	(1,151)
Non-taxable accounting gain	(1,798)	-
Stock-based compensation	443	132
Non-taxable accretion of subordinated notes	372	476
Change in rates and other	(1,987)	1,074
Future income tax provision	\$ 607	\$ 2,684

The components of the Company's future income tax assets and liabilities arising from temporary differences are as follows:

As at December 31,	2005		2004	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Non-capital losses	\$ 11,738	\$ -	\$ 16,481	\$ -
Obligations under gas sale and transportation contracts	1,900	-	2,196	-
Asset retirement obligations	2,455	-	829	-
Capital assets	-	15,006	-	19,076
Subordinated notes	470	-	450	-
Investment tax credits	4,137	-	-	-
Share issue costs	1,516	-	250	-
Other	110	-	-	-
	22,326	15,006	20,206	19,076
Valuation allowance	(17,678)	-	(16,622)	-
	\$ 4,648	\$ 15,006	\$ 3,584	\$ 19,076

The Company has reflected its future income tax liability, net of future tax assets, on the consolidated balance sheet.

Non-capital losses total \$1.6 million in Canada and \$29.0 million in Colombia, and expire between 2006 and 2012 in Canada and in 2011 in Colombia.

Note 12 – Technology Partnerships Canada Financing

Effective March 31, 2005, Technology Partnerships Canada ("TPC") announced their commitment to invest up to \$9 million towards the development and field demonstration of the Company's THAI™ technology at the WHITESANDS pilot project. Under the TPC funding commitment, TPC has agreed to contribute 20.134 percent of eligible expenditures for the WHITESANDS project to a maximum of \$9 million. Upon commercialization of the THAI™ technology TPC would be entitled to receive a royalty based on three separate revenue streams. The first stream is based on three percent of WHITESANDS pilot project revenues earned after January 1, 2006 with initial payments due May 1, 2010. The second stream is based on 0.6 percent of WHITESANDS Insitu Ltd. revenues (excluding pilot revenues) earned after January 1, 2009 with initial payments due May 1, 2010. The third stream is based on three percent of all third-party THAI™ licensing revenues earned after January 1, 2008 with initial payments due May 1, 2009. If, as of December 31, 2017 the cumulative royalty paid from the three royalty streams has not reached \$26.2 million, royalty payments will continue until \$26.2 million has been paid or until December 31, 2022, whichever occurs first.

The Company has received \$1.6 million subsequent to December 31, 2005 relating to expenditures incurred between August 26, 2004 and September 30, 2005 and has accrued an additional \$4.3 million related to expenditures up to December 31, 2005 which is included in accounts receivable and other current assets. Funding under this program is accounted for in accordance with CICA Handbook section 3800 "Government Assistance", whereby benefits receivable are recorded as a reduction of the related capital expenditures.

Note 13 – Related Party Transactions

The Company paid a \$0.2 million commitment fee in 2004 to secure a \$10 million credit facility from a company controlled by a former director of Petrobank. No amount was drawn on this facility which expired on December 30, 2004.

Note 14 – Financial Instruments and Financial Risk Management

The nature of the oil and natural gas operations and the issuance of debt expose the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company manages these risks by operating in a manner that minimizes its exposure to the extent practical, and through the periodic use of derivative instruments. The Board of Directors periodically reviews the results of all derivative activities and all outstanding positions.

Credit Risk

A substantial portion of the Company's accounts receivable are with customers and joint-venture participants in the oil and natural gas industry and are subject to normal industry credit risks. The carrying amount of accounts receivable reflects management's assessment of the credit risk associated with these customers and participants. The majority of the Company's Canadian oil production is sold to various large credit-worthy counterparties, while the majority of gas production is sold to a large international oil and gas company. Colombian oil production during 2004 and 2005 was sold to two counterparties, the Colombian state oil company, Ecopetrol, and a large international oil company. Typically, the Company's maximum credit exposure to customers is revenue from two months' sales. While counterparties to derivative instruments expose the Company to losses in the event of non-performance, the Company only deals with large credit-worthy institutions, and does not anticipate non-performance by these counterparties.

Commodity Price Risk Management

Long-Term Physical Gas Sale and Transportation Contracts

The Company is committed to deliver 2,225 GJ per day of natural gas under an escalating price contract which expires October 31, 2012. The wellhead price under this contract, at December 31, 2005, was set at \$3.53 per GJ. The contract provides for an annual price escalation between four percent and 10 percent, based on hydroelectric price inflation. Broader price re-determinations are to be made in 2007 and 2012, resulting in a new price that can vary from 65 percent to 135 percent of the previous year's price based on prevailing natural gas prices. Annual price escalation of four percent was used when calculating the fair value of this contract at December 31, 2005.

The Company held 5,275 GJ per day of firm transportation service on the ANG and PGT pipeline systems which expired October 31, 2005.

Fair Value of Financial Instruments

The estimated fair values of the following financial instruments at December 31, 2005 are:

	Carrying Value	Fair Value
Liabilities		
Physical gas sale contract	\$ 5,650	\$ 14,971
Subordinated notes	\$ 49,044	\$ 49,907

The fair values of the Company's remaining financial instruments at December 31, 2005 approximate their carrying values. Fair value of the physical gas sale contract is determined based on the estimated cash payment necessary to settle the contract at December 31, 2005. Cash payments are calculated based on discounted cash flow analysis using prevailing market prices at the time. The estimated fair value of the subordinated notes is based on public trading values as of December 31, 2005.

Note 15 – Supplemental Cash Flow Information

	2005	2004
a) Changes in other non-cash items were as follows:		
Accounts receivable and other current assets	\$ (8,664)	\$ 8,465
Less: accrued financing items (Note 12)	5,864	-
	\$ (2,800)	\$ 8,465
Accounts payable and accrued liabilities	30,941	(7,044)
	\$ 28,141	\$ 1,421
Changes relating to:		
Attributable to operating activities	\$ (1,003)	\$ 8,568
Attributable to financing activities	\$ -	\$ 25
Attributable to investing activities	\$ 29,144	\$ (7,172)
b) Other cash flow information:		
Cash taxes paid	\$ 1,542	\$ 1,057
Cash interest paid (received)	\$ (1,124)	\$ 1,131
Cash interest paid on subordinated notes	\$ 8,429	\$ 11,471

Note 16 – Commitments and Contingencies

The Company has first-phase work commitments remaining on its five new exploration contracts in Colombia totaling an additional US\$5.3 million which is to be incurred before October 2006 and includes reprocessing 2-D and 3-D seismic, shooting additional 3-D seismic, and drilling one well on the Joropo Block in the Llanos Basin. Upon completion of the first-phase commitments, the Company can elect to return the block to the National Hydrocarbon Agency ("ANH") or proceed to a second-phase by drilling one well per block.

The Company's remaining work commitments on the three new technical evaluation areas ("TEAs") in Colombia are expected to total US\$0.9 million until October 2006 and include reprocessing and evaluating existing 2-D seismic, and performing regional studies including the feasibility of the Company's patented THAI™ heavy oil recovery process. Upon expiry of the contracts, the Company has the option to negotiate an exploration block within the TEA. During the contract period, the Company also has a right of first refusal over any exploration blocks proposed by third parties within the TEA.

The Company has an option to secure a rig in Colombia for a minimum 16-month term commencing in mid-2006 for approximately US\$13.0 million.

The Company is committed to spend US\$2.1 million over five years for air compression rental at the WHITESANDS pilot project. The term is expected to commence in the first half of 2006.

Petrobank is committed to payments under operating leases for office space, net of sub-lease arrangements, as follows:

Year	
2006	\$ 661
2007	301
	\$ 962

Petrobank has issued letters of credit totaling \$1.9 million in connection with the Company's exploration contracts in Colombia and as guarantees to third parties for outstanding contractual obligations.

The Company is party to certain legal actions arising in the normal course of business, the outcome of which cannot be reasonably determined. In the opinion of management, the resolution of these matters will not have a material effect on the Company's financial position or results of operations.

The Company has entered into certain types of contracts, particularly those related to divestiture transactions that require it to indemnify parties against possible third-party claims. These obligations are typically limited to the amount of sales proceeds and expire within one year in the case of property dispositions. Management does not expect payments, if any, related to such matters to have a material effect on the Company's financial position or results of operations.

Note 17 – Segmented Information

Years ended December 31,

	2005			2004		
	Canada ⁽¹⁾ and Other	Colombia	Total	Canada ⁽¹⁾ and Other	Colombia	Total
Revenues						
Oil and natural gas	\$ 44,904	\$ 20,177	\$ 65,081	\$ 51,643	\$ 21,734	\$ 73,377
Royalties	(9,243)	(1,614)	(10,857)	(11,629)	(1,743)	(13,372)
	35,661	18,563	54,224	40,014	19,991	60,005
Expenses						
Production	5,341	3,571	8,912	11,475	3,816	15,291
Transportation	866	-	866	1,526	-	1,526
General and administrative	4,194	3,454	7,648	4,500	2,634	7,134
Depletion, depreciation and accretion	9,408	6,974	16,382	23,170	10,197	33,367
Segmented income (loss)	\$ 15,852	\$ 4,564	\$ 20,416	\$ (657)	\$ 3,344	\$ 2,687
Non-segmented items						
Stock-based compensation			(1,168)			(338)
Interest on bank debt			-			(1,246)
Interest on subordinated notes			(8,429)			(11,471)
Gain			4,744			16,632
Loss on repurchase of subordinated notes			(968)			-
Other income (expense)			844			(1,277)
Capital taxes			(2,024)			(1,470)
Future income taxes			(607)			(2,684)
Net income			\$ 12,808			\$ 833
Identifiable assets	\$ 157,867	\$ 103,115	\$ 260,982	\$ 134,550	\$ 70,842	\$ 205,392
Capital expenditures	\$ 79,728	\$ 38,424	\$ 118,152	\$ 33,995	\$ 13,906	\$ 47,901

(1) Canada includes Heavy Oil Business Unit expenditures of \$32.6 million in 2005 (2004 – \$3.6 million), identifiable assets at December 31, 2005 of \$48.2 million (2004 – \$9.4 million), and negligible revenues and expenses.

STRENGTH in our partners

Abbreviations

ANH	National Hydrocarbon Agency (Colombia)
bbl	barrel
bcf	billion cubic feet
boe	barrel of oil equivalent
bopd	barrels of oil per day
boepd	barrels of oil equivalent per day
bpd	barrels per day
CBM	coal bed methane
GJ	Gigajoules
IPC	Incremental Production Contract
IPO	initial public offering
km	kilometres
m	metres
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcfpd	mcf per day
mmbtu	millions of British thermal units
mmcf	million cubic feet
NPV	net present value
NGL	natural gas liquids
P+P	proved + probable
TEA	Technical Evaluation Area
WI	working interest
WTI	West Texas Intermediate

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(2) Member of the Audit Committee

(3) Member of the Reserves Committee

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Reserve Engineers

Sproule Associates Limited
Calgary, Alberta

DeGolyer and MacNaughton
Dallas, Texas

Exchange Listings

The Toronto Stock Exchange
SYMBOLS: **PBG, PBG.NT.A**

Oslo Børs

SYMBOLS: **PBG**
(PBG.N until June 2006)

Securities Filings

www.sedar.com
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Forward Looking Statements

This annual report contains forward-looking statements that are generally identifiable by terms such as anticipate, believe, budget, intend, estimate, expect, outlook, plan or other similar words, and include future capital investment plans. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; the ability to economically test, develop and utilize the Company's patented technologies, the feasibility of the technologies; and other factors, many of which are beyond the control of the Company. There is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

BOE conversions are presented at six mcf = one barrel.



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